

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Don Storm
Tom Burton
Marshall Johnson
Cynthia A. Kitlinski
Dee Knaak

Chair
Commissioner
Commissioner
Commissioner
Commissioner

In the Matter of Petition of
Northern States Power Company's
Gas Utility for Authority to
Change Its Schedule of Gas Rates
for Retail Customers Within the
State of Minnesota

ISSUE DATE: September 1, 1993

DOCKET NO. G-002/GR-92-1186

FINDINGS OF FACT, CONCLUSIONS OF
LAW, AND ORDER

PROCEDURAL HISTORY

I. INITIAL PROCEEDINGS

On November 2, 1992, Northern States Power Company's Gas Utility (NSP or the Company) filed a petition seeking a general rate increase of \$14,873,000, or 5.83%, effective January 1, 1993.

On December 14, 1992, the Commission issued Orders accepting the Company's filing, suspending the proposed rates, and setting the matter for contested case proceedings. The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Allan W. Klein to the case. The Office of Administrative Hearings also assigned Administrative Law Judge Richard C. Luis to NSP's concurrent electric rate case, Docket No. E-002/GR-92-1185.

On December 18, 1992, ALJs Klein and Luis convened a joint gas and electric prehearing conference.

On December 29, 1992, the ALJs issued an Advance Notice of Key Decisions in Prehearing Order. In that Notice the ALJs determined the order of trial on the gas, electric and common issues. The ALJs also issued an Order Setting Deadline for Intervention.

On December 31, 1992, the Commission issued its ORDER ADOPTING INTERIM RATES in the gas case, authorizing an interim rate increase of \$8,386,000, effective January 1, 1993.

On February 2, 1993, the ALJs issued a Prehearing Order establishing the hearing schedule and procedural guidelines. The Order determined that Judge Klein would hear gas issues and certain issues common to the gas and electric cases. Judge Luis would hear electric issues and certain other common gas and electric issues. The Prehearing Order also granted intervenor

status in the gas case to the following parties: the Department of Public Service (the Department); the Residential Utilities Division of the Office of the Attorney General (RUD-OAG); the Suburban Rate Authority (SRA); and the City of St. Paul.

All parties filed testimony on issues common to the gas and electric cases on February 22, 1993.

On March 1, 1993, the Department filed testimony on gas-only issues. The Department was the only intervenor to file such testimony. The other intervenors testified only on issues common to the gas and electric cases.

On February 22, 1993, the Company filed a Motion to Update Filing. No party opposed the Motion, and it was granted by Judge Klein. As a result of changes thereafter incorporated into the Company's initial brief, the Company's rate increase proposal in the gas case decreased from \$14,873,000 to \$12,387,000.

II. PARTIES AND REPRESENTATIVES

A. Intervenors

The intervenors and their representatives in this matter are as follows:

Minnesota Department of Public Service, represented by Julia E. Anderson and Joshua S. Wirtschafter, Special Assistant Attorneys General, NCL Tower, 445 Minnesota Street, St. Paul, Minnesota 55101-2130;

Residential Utilities Division of the Office of the Attorney General, represented by Eric F. Swanson and Gary R. Cunningham, Special Assistant Attorneys General, Suite 1200, NCL Tower, 445 Minnesota Street, St. Paul, Minnesota 55101-2130;

The Suburban Rate Authority, represented by James M. Strommen, Holmes & Graven, 470 Pillsbury Center, Minneapolis, Minnesota 55402;

The City of St. Paul, represented by Thomas J. Weyandt, 800 Landmark Towers, 345 St. Peter Street, St. Paul, Minnesota 55102;

In addition, the following parties and their representatives addressed the issues common to the gas and electric utilities:

Minnesota Department of Public Service, represented by Dennis D. Ahlers, Mark A.R. Chalfant, Brent Vanderlinden and Scott Wilensky, Special Assistant Attorneys General;

Residential Utilities Division of the Office of the Attorney General, represented by Eric F. Swanson and Gary R. Cunningham, Special Assistant Attorneys General;

Suburban Rate Authority, represented by James M. Strommen;

Minnesota Energy Consumers (MEC), represented by James J. Bertrand, Leonard, Street & Deinard, 50 South 5th Street, Suite 2300, Minneapolis, Minnesota 55402-2436.

B. The Company

The Company was represented in the gas rate case by Gene R. Sommers and James P. Johnson, Northern States Power Company, 414 Nicollet Mall, Minneapolis, Minnesota 55401. In matters common to the gas and electric utilities, the Company was represented by Audrey A. Zibelman, Michael J. Hanson and David A. Lawrence, Northern States Power Company, 414 Nicollet Mall, Minneapolis, Minnesota 55401.

III. PUBLIC HEARINGS AND PUBLIC TESTIMONY

The ALJs held joint public hearings to receive comments and questions from non-intervening ratepayers. At each hearing, persons were free to speak to both electric and gas issues. The dates and locations of the hearings are as follows:

March 10, 1993	Montevideo
March 11, 1993	Minneapolis
March 17, 1993	Dilworth
March 18, 1993	St. Cloud
March 24, 1993	St. Paul
March 25, 1993	Coon Rapids
March 30, 1993	Winona
March 31, 1993	Mankato

In all, 48 ratepayers spoke at the combined public hearings. Of this number, 13 favored the proposed increases, 27 opposed them, and eight were either neutral or expressed both sentiments. Only a few speakers addressed the gas issues; most addressed the proposed increase in electric rates.

Persons who favored the proposed rate increases spoke from two perspectives: as shareholders; and as representatives of non-profit organizations. The latter group cautioned against NSP's becoming so "lean and mean" that employees were unable to contribute to charitable or community organizations through either donations or volunteer efforts.

In St. Cloud, a petition was introduced into the record bearing signatures of 780 NSP customers who were opposed to any rate increase for either electric or gas.

A number of individuals stated that at some point they had been forced by financial circumstances to choose between paying utility bills or paying their rent or mortgage. Some of these speakers favored a low income discount.

Most written comments were directed to the electric rather than to the gas issues. Most comments which were directed to the proposed gas increase reflected opposition rather than support. Several persons compared the size of the proposed increases with recent cost-of-living increases in social security and other similar government programs.

IV. EVIDENTIARY HEARINGS

Administrative Law Judge Klein held evidentiary hearings in St. Paul, Minnesota, on April 27, 28, and 29, 1993 regarding combined gas and electric issues, and on April 30, May 3 and 4, 1993 regarding gas issues alone.

V. PROCEEDINGS BEFORE THE COMMISSION

Administrative Law Judge Klein filed a report on July 6, 1993, in which he addressed all gas and all common issues. On August 4 and 6, 1993, the Commission heard oral argument regarding certain common issues and the contested gas issues. This Order will address the issues common to the gas and electric cases, and all gas utility issues.

Upon review of the entire record of this proceeding, the Commission makes the following Findings, Conclusions, and Order.

FINDINGS AND CONCLUSIONS

VI. JURISDICTION

The Commission has general jurisdiction over the Company under Minn. Stat. §§ 216B.01 and 216B.02 (1992). The Commission has specific jurisdiction over rate changes under Minn. Stat. § 216B.16 (1992).

The case was properly referred to the Office of Administrative Hearings under Minn. Stat. §§ 14.48-14.62 (1992) and Minn. Rules, part 1400.0200 et seq.

VII. FURTHER ADMINISTRATIVE REVIEW

Under Minn. Rules, part 7830.4100, any petition for rehearing, reconsideration, or other post-decision relief must be filed within 20 days of the date of the Order. Such petitions must be filed with the Executive Secretary of the Commission, must specifically set forth the grounds relied upon and errors claimed, and must be served on all the parties. The filing should include an original, 13 copies, and proof of service on all parties.

Adverse parties have ten days from the date of service of the petition to file answers. Answers must be filed with the Executive Secretary of the Commission and must include an original, 13 copies, and proof of service on all parties. Replies are not permitted.

The Commission, in its discretion, may grant oral argument on the petition or decide the petition without oral argument.

Under Minn. Stat. § 216B.27, subd. 3 (1992), no Order of the Commission shall become effective while a petition for rehearing is pending or until either of the following: ten days after the petition for rehearing is denied or ten days after the Commission has announced its final determination on rehearing, unless the Commission otherwise orders.

Any petition for rehearing not granted within 20 days of filing is deemed denied. Minn. Stat. § 216B.27, subd. 4 (1992).

VIII. THE COMPANY

NSP's gas utility serves as a local distribution company providing retail gas service to approximately 294,000 customers in Minnesota. Most of its customers are located in the "metro east region," which is comprised of the City of St. Paul and suburbs to the east, north and south of that City. In addition, the Company serves customers in the St. Cloud/Sauk Rapids area, the Northfield and Faribault areas, the East Grand Forks/Moorhead area, and communities such as Red Wing, Wabasha, and Winona.

NSP's gas utility has 422 employees. It also receives support from NSP's corporate operations and the Company's electric utility.

IX. BURDEN OF PROOF

Minn. Stat. § 216B.16, subd. 4 (1992) states: "The burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change."

The Minnesota Supreme Court has articulated standards for the burden of proof in rate cases. In the Matter of the Petition of Northern States Power Company for Authority to Change Its Schedule of Rates for Electric Service in Minnesota, 416 N.W. 2d 719 (Minn. 1987). In the Northern States Power case the Court divided the ratemaking function of the Commission into quasi-judicial and legislative aspects. The Commission acts in a quasi-judicial mode when it determines the validity of facts presented. Just as in a civil case, the burden of proof is on the utility to prove the facts by a fair preponderance of the evidence. Such items as claimed costs or other financial data are facts which the utility must prove by a fair preponderance of the evidence.

The Commission acts in a legislative mode when it weighs the facts presented and determines if proposed rates are just and reasonable. Acting legislatively, the Commission draws inferences and conclusions from proven facts to determine if the conclusion sought by the utility is justified. The Commission weighs the facts in light of its statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates. In its legislative capacity, the Commission forms determinations such as the usefulness of a claimed item, the prudence of company decisions, and the overall reasonableness of proposed rates.

The utility therefore faces a two part burden of proof in a rate case. When presenting its case in the rate change proceeding, the utility has the burden to prove its facts by a fair preponderance of the evidence. The utility also has the burden to prove, by means of a process in which the Commission uses its judgment to draw inferences and conclusions from proven facts, that the proposed rates are just and reasonable.

X. TEST YEAR

The Company proposed the twelve-month period from January 1, 1993 through December 31, 1993 as its test year in this proceeding. The test year data was fully projected, based on the Company's budgeting process. The ALJ found that the Company's fully forecasted test year was consistent with the Company's last filing and was reliable for ratemaking purposes.

The Commission agrees with the ALJ that the Company's proposed test year is appropriate. The Commission accepts the Company's proposed test year for purposes of this general rate case.

XI. RATE BASE

In its initial filing, NSP proposed a rate base of \$214,676,000. The Company reduced this amount to \$214,623,000 in its February 22, 1993 update and increased it to \$214,820,000 in its initial brief. The Commission will use the originally filed amount as the starting point in its determination and computation of the rate base in this proceeding. Individual rate base issues will be discussed below.

A. Incentive Compensation

As discussed in the Operating Income Section XII (A), the Commission disallowed recovery of incentive compensation in rates. NSP does not capitalize any of the incentive compensation. However, NSP does capitalize a portion of the pension on the incentive compensation. The amount of the pension capitalized in the Minnesota jurisdiction gas utility is \$18,480.

The Commission finds that rate base should be reduced by \$9,240, the average of the beginning and end of year balances.

B. Employee Loans

As a benefit to its employees, the Company makes loans to employees to purchase personal computers (PCs). The loans are for 36 months at zero interest.

The question at issue is whether the balance of employee loans should be included in rate base.

The Company argued that while there may not be a direct relationship between these loans and the provision of utility service, there exists an indirect benefit to customers. Approximately 50% of NSP's employees utilize PCs in some way as part of their job. NSP claimed it seems reasonable to assume that employee's computer knowledge and job skills are enhanced by the use of PCs at home.

The Department recommended that ratepayers not be responsible for this employee benefit, because it does not contribute to the provision of utility service. The Department argued that if a return on the loan balance is required, the return should either be provided by the employees who receive the loans or continue to be absorbed by the shareholders.

The ALJ rejected the inclusion of employee loans in rate base finding that the relationship between these loans and the provision of utility service is too remote to justify requiring ratepayers to pay a return on these loans.

The Commission agrees that the Company has not demonstrated that employees' home use of computers benefits the ratepayers. The Company did not document what portion of the employees who purchased computers use a PC as part of their job. The Commission believes that the appropriate method for the Company to provide computer training for employees is through NSP's training program where the training would be specifically related to the job.

The Commission concludes that employee loans should not be included in rate base, resulting in a reduction to rate base of \$106,903.

C. CWIP/AFUDC

Historically, there has been substantial controversy over the treatment of construction work in progress (CWIP) for rate purposes. Minnesota tends to allow CWIP in rate base with the allowance for funds used during construction (AFUDC) offset to the income statement.

Minn. Stat. §216B, subd. 6a provides:

Construction work in progress. To the extent that construction work in progress is included in the rate base, the commission shall determine in its discretion whether and to what extent the income used in determining the actual return on the public utility property shall include an allowance for funds used during construction, considering the following factors:

- (a) the magnitude of the construction work in progress as a percentage of the net investment rate base;
- (b) the impact on cash flow and the utility's capital costs;
- (c) the effect on consumer rates;
- (d) whether it confers a present benefit upon an identifiable class or classes of customers; and
- (e) whether it is of a short term nature or will be imminently useful in the provision of utility service.

In the original filing, NSP included \$117,000 of AFUDC as test year income. The related CWIP included in rate base is \$8.015 million. NSP calculates AFUDC monthly on the CWIP balance excluding short term projects, non-construction projects, and completed projects not reclassified to plant.

The SRA argued that the length of time required to construct the plant is not the relevant factor. The SRA recommended that AFUDC be calculated on short term CWIP and that the CWIP balance be based on the beginning of year/end of year average rather than the monthly balances. This would increase the amount of AFUDC included as income for the test year by \$504,000.

As a result of information request responses from NSP, the SRA concluded that its original recommendation needed to be revised. The SRA indicated that it lacked the time and resources to pursue its original position, and withdrew the original position at hearing.

NSP argued that its practices have been consistent since its first rate case in 1975. It further argued that the Commission addressed NSP's CWIP and AFUDC accounting and budgeting procedures in Docket Nos. E-002/GR-81-342 and E-002/GR-85-558 and concluded that NSP's treatment was consistent with past Commission treatment.

The Company argued that due to the construction fluctuations throughout the year, it is more appropriate to calculate AFUDC based on monthly balances as done by NSP. The NSP method is more accurate than the beginning of year/end of year method recommended by the SRA. In addition, the SRA failed to reduce CWIP for non-construction expenditures and CWIP amounts which should be reclassified as "in service." After making these adjustments, the impact of the SRA recommendations on NSP's jurisdictional revenue requirement is minimal and would not justify a policy change.

In its brief, the SRA recommended that the Commission adopt rate filing rules requiring detailed information on CWIP and AFUDC. The SRA argued that this information would allow parties and the Commission to be in a position to evaluate the impacts of the Company's proposed ratemaking treatment of CWIP and AFUDC.

In reply, NSP argued that it provided the necessary information to the SRA in response to information requests. Detailed balances for each CWIP item were provided in the original filing. Rate case filing requirements should not be modified because one party could not devote the resources to understand the procedures.

The ALJ recommended no adjustment. The ALJ declined to recommend adopting a rule as recommended by the SRA, stating that the SRA proposal was too late to receive detailed scrutiny.

The Commission concludes that the calculation of AFUDC made by the Company is consistent with past Commission treatment of this issue and the result is reasonable to use in setting rates in this case.

D. Depreciation Study

When NSP submitted this filing it had submitted its 1993 annual study for certification of production plant depreciation rates in Docket No. G,E-002/D-92-1066 and its five year study for transmission, distribution, and general plant depreciation rates in Docket No. G,E-002/D-92-869. At the time of its original filing, NSP proposed that the rates from these dockets, if approved, be incorporated into this rate case expenses. The Commission approved new depreciation rates in its Orders in these dockets dated April 23, 1993. The incorporation of the approved rates results in a decrease in depreciation expenses of \$307,000.

The Department and the ALJ agreed that this adjustment is appropriate. The Commission finds that factoring the Company's 1993 depreciation schedule into test year expenses will result in an accurate picture of depreciation expenses. The Commission will accept this adjustment, which will increase rate base by \$93,000 and increase net income by \$184,000.

E. Expansion of Maplewood Propane Facility

NSP budgeted \$1.3 million to expand its Maplewood propane vaporization capability. The project will add 16,000 Mcf per day of propane vaporization capability. NSP stated the addition is a low cost method of replacing pipeline contract and warranted supply. After the expansion, NSP will have two separate facilities capable of providing 44,000 Mcf per day of propane vaporization equivalent. As a result NSP could lose either propane facility under design conditions and still protect firm customers.

The Department supported the Company's proposed expansion citing the substantial savings to be realized from the project and system enhancement.

The ALJ agreed with the proposed expansion.

The Commission concludes that the expansion of the Maplewood peaking facility will allow the Company to reduce pipeline costs, resulting in substantial net savings to ratepayers. In addition the expansion will enhance the reliability of NSP's system on peak days. The Commission finds that it is appropriate to increase rate base by the \$1.3 million cost of the expansion.

F. PGA True-up

NSP proposed that the true-up balance of its PGA as of June 30, 1992 in the amount of \$1,127,901 be included in rate base. NSP argued that it has underrecovered its gas cost expense for the last four (1989-92) years. This has resulted in the equivalent of a customer receivable with no corresponding carrying cost compensation from ratepayers. By including the true-up balance in rate base, NSP will earn a return on the underrecovery of gas costs.

The Department argued that these costs do not belong in rate base. Gas costs are recovered first in the base cost of gas and then through the PGA, which attempts to collect the difference between the actual cost of gas and the amount included in rates. Any difference between the actual gas costs incurred and the actual gas costs collected during a specific 12 month period are recovered in the annual PGA true-up mechanism. If the Company wants to collect a carrying charge on its PGA true-up costs, it should request such a charge in a miscellaneous petition, probably its next PGA true-up filing.

The Department stated that the Company is requesting a change from a three month window to a one month window for reflecting gas costs in its PGA in the instant docket. The Department argued that this change should cause the annual true-up balance to be less in the future and could result in an overrecovery. This change causes doubt as to whether NSP's consistent underrecovery will continue after the test year. It recommended reducing rate base by the PGA true-up balance of \$1,127,901.

The ALJ adopted the Department's position recommending reducing NSP's proposed rate base by the PGA true-up balance.

The Commission agrees with the Department and the ALJ that changes in gas costs are properly recovered through the PGA. NSP is allowed to recover on a current basis changes in purchased gas costs through the PGA. Any difference between the actual costs and the costs collected in the PGA are recovered through the PGA true-up. This special provision allows the Company to remain whole between rate cases for gas costs, which are the majority of NSP's O&M expenses. Changes in the level of other costs can only

be recovered in rates as a result of a rate case. The Commission concludes that the change in the PGA window makes it unlikely that a consistent underrecovery will continue. (The Commission approved the change in the PGA calculation window, see Section XV (T). The Commission finds that the PGA true-up balance should not be included in rate base and rate base will be reduced by \$1,127,901.

G. Manufactured Gas Plant (MGP) Cleanup Costs

In the last NSP gas case, Docket No. G-002/GR-86-160, the Commission authorized amortization of \$856,248 over five years for the Faribault MGP cleanup costs. NSP's original filing in the instant case included the insurance proceeds for the Faribault MGP cleanup costs as a credit to rate base. The Company later conceded that the insurance proceeds should be refunded to ratepayers. NSP argued that it had cleanup costs for the Faribault MGP (gas utility) and Sunnybrook Farm (electric utility) and that the total insurance recovery of \$632,548 was for both Faribault and Sunnybrook Farm. NSP also argued that two thirds of the insurance proceeds, or \$421,720, were related to Faribault. The Company argued that support for the one third/two thirds allocation was available to be reviewed at the Company's offices as stated in an information request response to the Department. NSP stated that an additional \$50,000 would be spent in 1993 for cleanup at Faribault. The Company proposed to return to ratepayers \$371,720 (\$421,720 less \$50,000) amortized over five years (\$74,344 per year) with nothing included in rate base. The Company's final proposal includes increasing rate base working capital by \$126,025 to remove the insurance proceeds originally included in rate base.

The Department recommended that 100% of the insurance proceeds be allocated to the gas utility and be amortized over 4 years at \$158,137 per year. The Department argued that NSP had not demonstrated that only two thirds of the insurance proceeds were for Faribault. The Department stated that the Company has not provided evidence that the \$50,000 of additional cleanup costs will be spent in the test year; therefore, they should not be allowed. The Department also recommended that the unamortized portion of the insurance proceeds be included as a credit to rate base.

The ALJ recommended that two thirds of the recovery (\$421,076) should be allocated to Faribault, that the additional \$50,000 of cleanup costs be deducted from the refund, and that the amortization period for the refund should be four years. Rate base should be reduced by the unamortized balance of \$278,307.

The Commission agrees with the Company and the ALJ that two thirds of the insurance proceeds should be allocated to Faribault. The record supports the fact that the proceeds were for both Faribault and Sunnybrook and that two thirds is a reasonable estimate of the Faribault portion. The Commission finds that it is appropriate to reduce the refund by \$50,000 for

current year costs rather than defer that amount for later recovery. A four year amortization period is reasonable because it corresponds to the amortization period for rate case costs. The Commission concludes that since the unamortized cleanup costs were not included in rate base, the unamortized insurance proceeds refund should not be included in rate base. The amount to be included as a refund in the form of a revenue credit is \$371,720 (\$421,720 less \$50,000) and annual amortization is \$92,930.

H. CNG Investment Costs

In its initial filing, the Company included the cost of 14 compressed natural gas (CNG) vehicle conversion kits in the transportation equipment account in rate base. The gross cost of the kits was \$49,306 and the net was approximately \$30,800. NSP argued that the Company would generate a savings of approximately \$0.56 per gallon of fuel use due to the use of CNG fuel and its own CNG refueling facilities. This would equate to a payback period of 5 years or less for all NSP vehicle types presently being converted. The Company argued that all the costs are cost justified but if an adjustment is made, the amount should be \$30,800 because only the net amount after depreciation is included in rate base.

The Department argued that these costs should be included in rate base only if the benefits at least equal the costs. The Department stated that the responses to data requests did not provide adequate information to do a cost/benefit analysis. The Company did not provide information on the type and amount of fuel used, miles driven, and documentation of the operations and maintenance cost of the vehicles and the refueling station. The Department argued that none of the cost savings information provided by the Company was verifiable. The payback calculations didn't use the actual costs of the kits, and graphs provided by NSP appear to indicate that the payback of 9.5 to 35 years is considerably longer than the vehicle lives of three to five years. The Department recommended removing the incremental cost of \$49,306 for CNG-vehicle conversions from the rate base. The Department argued that NSP had non-regulated use of the refueling station in 1992, and that the test year costs were not adjusted to remove these costs. The \$49,306 is a proxy for the CNG kit costs and the costs that should have been removed from O&M.

The ALJ agreed with the Department that NSP had not supported its payback assertion nor its cost-benefit analysis. It also appears not to have considered other cost components in its overall cost analysis, such as costs of executive time, compressor maintenance, and billing functions. The ALJ agreed with the Company that only the net amount should be removed and recommended that NSP's rate base should be reduced by \$30,800.

The Commission agrees that because the cost of the CNG kits is over and above the cost of the vehicles, that these costs should be included in rates only if the benefits outweigh the costs.

The Commission concludes that NSP has not kept adequate records to support any proof of benefits to ratepayers. The Commission finds that \$49,306 is a reasonable proxy for the cost in rate base and the unquantified O&M costs that should be excluded. Rate base is reduced by \$49,306.

I. Gas Storage Inventory

NSP included \$7,653,000 of underground natural gas inventory in rate base. This amount is the 13 month average of the estimated gas inventory for the test year (1993). The Department and the ALJ recommended that the Commission accept the rate base treatment.

NSP requested that in addition to the rate base treatment, the Company be allowed a carrying charge on the true-up of the inventory as part of the PGA. The carrying charge on the true-up would be NSP's overall after-tax cost of capital. The Company argued that rate base treatment alone would be appropriate for stable inventories. But because Federal Energy Regulatory Commission (FERC) Order 636 has changed the gas market, inventory levels could swing substantially from year to year. With unstable inventories, a carrying charge protects both the Company and the ratepayer.

The Company stated that it would agree to use a miscellaneous filing to obtain a return on increases in the inventory level between rate cases rather than its PGA proposal, so long as the tariff was modified to specifically allow the filing.

The Department recommended that the inventory true-up be denied. The Department argued that if NSP's storage inventory were to experience a large swing the Company should file a miscellaneous petition for recovery of carrying costs as Midwest Gas did in 1991. Because the Company's proposed inventory true-up in the PGA would be automatic, neither the Commission nor any party would have the opportunity to examine and discuss the reasonableness or appropriateness of the addition to rates. A miscellaneous filing would allow any proposed adjustment to be fully examined and approved before it would be charged to ratepayers.

The ALJ stated that absent unusual circumstances, a utility possesses the opportunity and bears the risks, between rate cases, associated with increases and decreases in inventory from the level projected in the test year. The ALJ recommended that NSP's request for an automatic carrying charge be denied. The ALJ agreed with the parties that the Company should have the opportunity to make a miscellaneous filing between rate cases, allowing it to seek recovery for carrying costs associated with the actual changes in inventory levels. A tariff change is not necessary to assure that such a filing can be made; a Commission order is sufficient to state the Commission's intention.

The Commission agrees that the underground gas storage inventory should be included in rate base. This is consistent with past Commission treatment of gas inventory. The Commission also agrees that the utility bears the risk for changes in rate base, including gas inventory, between rate cases. It is not appropriate to shift this risk to the ratepayers through an automatic carrying charge. The Commission concludes that automatically allowing the Company to include a carrying charge for changes in gas storage inventory without any review is not in the best interests of the ratepayers. Before any carrying charge is included in rates it must be fully examined. The Commission agrees with the Department and the ALJ that a miscellaneous filing when the inventory variance occurs is the appropriate method to address the proposed carrying charge. The Commission approves a modification of the tariff that simply reflects that the proposed miscellaneous filing will be allowed. This is in no way indicating that such a filing will be approved.

J. Unamortized Rate Case Costs

The Company's filing includes \$214,000 of rate case expenses in the test year operating expenses and \$206,000 of unamortized rate case expenses in rate base. NSP originally proposed a two year amortization but later stated that three years would be acceptable.

The Company stated that the Commission deemed it appropriate to include unamortized rate case expenses in rate base in the 1987 electric case. It argued that a rate case is not primarily for the benefit of the shareholders. The rate case is a process necessary to fulfill the service obligation of a public utility. Customers expect safe, reliable, and dependable gas service at a reasonable price (which is regulated by the Commission). Rate case expenses are simply a cost of doing business for an industry that is regulated. It is necessary to properly recognize the time value of money via the carrying cost on required expense deferrals.

The Department argued that rate cases are filed primarily for the benefit of shareholders (i.e. to maintain or increase earnings). Ratepayers should not be required to provide a return on these expenses during the amortization period. In the 1986 gas rate case, the Commission denied rate base treatment for the unamortized rate case expenses related to the test year, stating that, "the historical evidence of more than full recovery indicates that an extraordinary adjustment to put the unamortized balance in rate base would unduly burden ratepayers and is not necessary to protect the shareholders." The Department also stated that NSP had overrecovered rate case costs from the 1986 case. The Department stated that the payments for rate case costs can occur after the test year even though they are included in the test year. The Department recommended removing unamortized rate case cost from rate base, resulting in a reduction of \$206,000.

The ALJ recommended that consistent with the Commission's past practice, rate base treatment be denied on the grounds that expenses are not normally recoverable as an investment in rate base. See NSP, Docket No. G-002/GR-86-160.

The Commission notes that it reconsidered its decision on rate case expenses in Docket No. G-002/GR-86-160. In the reconsideration Order the Commission allowed NSP to recover the rate case costs from the refund. As stated on page 2 of the April 1, 1987 ORDER AFTER RECONSIDERATION AND REHEARING "This will eliminate the problem of determining the appropriate amortization period. It will also eliminate any overrecovery or underrecovery of rate case expense because of the selected amortization period." Because the rate case costs were recovered in full from the refund, the issue of unamortized rate case cost in rate base was eliminated. Therefore the Commission did not address it in reconsideration, neither confirming nor denying the decision in the original Order. Also because the rate case costs were recovered from the refund, they were not included in the rates set in the 1986 rate case as alleged by the Department.

The Commission finds that rate case expenses are allowed as an operating expense in order to recognize the normal regulatory activity of the utility. However, if the full amount of rate case expenses were allowed in the test year, a utility that did not file a rate case every year would recover these costs several times over. Thus, for purposes of test year expense, rate case expenses are normally spread over a longer period of time than one year. That period attempts to reflect the length of time the rates will be in effect before a new rate case is filed.

Because rate case expenses are recovered over a period of years similar to the Company's investment in plant, these costs should be treated in a similar manner. The Commission concludes that unamortized rate case cost should be included in rate base. The amount to be included in this case is \$154,000, which is the average test year unamortized balance using a four year amortization period (see XII Section E).

K. Rate Base Summary

The Commission's findings and conclusions relating to the Company's rate base result in a Minnesota jurisdictional average rate base of \$213,405,000 for the test year as shown below (000's omitted):

Utility Plant in Service	\$395,021
Less: Accumulated Depreciation	<u>155,741</u>
Net Utility Plant in Service	\$239,280
Construction Work in Progress	8,011
Accumulated Deferred Income Taxes	(39,948)
Working Capital:	
Cash Working Capital	(7,422)
Gas in Storage	12,517
Materials and Supplies	3,343
Prepayments	609
Customer Advances & Deposits	(496)
Misc Def Debits & Credits	(1,144)
Pension Funding Liability	(596)
FAS 106 Provision &	(903)
Amortization	
Unamortized Rate Case Expense	<u>154</u>
Total Working Capital	<u>\$ 6,062</u>
TOTAL AVERAGE RATE BASE	<u>\$213,405</u>

XII. OPERATING INCOME STATEMENT

The Commission will begin with NSP's originally filed net operating income of \$12,826,000. In subsequent paragraphs the Commission will discuss the proposed adjustments to the Company's test year income statement.

A. Employee Compensation

1. Introduction

The Company sought recovery of approximately \$237,415,000 in employee cash compensation for the combined gas and electric utilities. Approximately \$10 million of this amount represented sums potentially payable under an incentive compensation program. The program consists of six plans: an annual plan for employees in each branch of the Company's work force (bargaining, nonbargaining, management, and executive) and two long-term plans for officers and executives. Under the program a portion of every employee's compensation is contingent upon his or her organizational unit achieving quantifiable goals relating to safety, customer satisfaction, productivity, and cost control. Except for employees in the bargaining unit, eligibility for incentive compensation also depends upon achieving individual performance goals.

The Company claimed the incentive compensation program would help achieve two goals: (1) it would gradually reduce Company wage rates to the market median by avoiding the compounding effects of base salary increases; (2) it would reinforce employee behaviors the Company has determined are crucial to reaching its goal of becoming more customer-oriented. Parties challenged both wage rates and the reasonableness of the Company's incentive compensation program.

The Department urged the Commission to focus on wage levels as a whole as opposed to the design of individual compensation packages. The Department did, however, recommend disallowance of the costs of the long-term incentive plan for executives and the earnings per share component of the officers' annual plan, believing the first worked exclusively to the benefit of shareholders and the second risked weakening the commitment to the long term so crucial to the operation of a public utility. The Department also contended the Company's overall wage levels were significantly above market and should be reduced by 2.37% for ratemaking purposes. The Department disputed the Company's claim that its overall salary levels were similar to those of similar companies, arguing the Company's comparison group was not genuinely comparable. The Department contended Company salary levels as a whole were 7.37% above the market median.

The RUD-OAG, MEC, and SRA advocated disallowance of all costs attributable to the incentive compensation plan for the following reasons: (1) the plan as a whole, especially the executive and the long-term portions, seeks to transfer the risks of operation from shareholders to ratepayers and employees; (2) the plan's link between low rates and eligibility for incentive compensation is not adequately supported by a link between employee performance and rate levels; (3) the plan's requirement that departments spend their budgets, as well as not overspend them, fails to adequately protect ratepayers' interests in cost-cutting; (4) the plan is a "bonus" in disguise, and the Company has not demonstrated that a bonus is necessary to attract a work force capable of delivering high quality service at reasonable rates.

The Administrative Law Judge found NSP's overall compensation levels unreasonably high and that incentive compensation was the element raising them above market averages. ALJ Findings No. 271 and 274. He believed the Company should be granted some flexibility to pay above-market salaries and recommended rate recovery of overall wage levels up to 105% of the market median. He adjusted the Company's market median for defects in its comparison group and recommended an across-the-board disallowance of 2.37% of test year compensation expense.

He also found that properly designed incentive compensation plans were in the public interest; he did not find defects in the NSP plan justifying disallowance. He did express concern about the Company's retention of the option to decline to pay incentive compensation earned under the plan, an option management

exercised in 1992. His decision to limit recoverability of overall compensation to 105% of the market median was based in part on the possibility of this happening again. ALJ Discussion, p. 60.

2. Commission Action

a. Summary

The Commission accepts and adopts the Administrative Law Judge's findings that the Company's employee compensation levels are unreasonably high and that the component that raises them above market averages is the incentive compensation plan. The Commission finds that the benefits of the incentive compensation plan are speculative while the drawbacks are real. Given the significant plan deficiencies noted below, the Commission will take the most straightforward course of action and disallow recovery of all expenses associated with the incentive compensation plan.

b. Overall Compensation Levels

The Company stated its overall wage levels were above its target, which was 100% of the market median, and that the incentive plan was one of the tools it was using to bring salaries into alignment with the market median. The Department placed current salaries at 107.34% of the market median. The Department also argued the Company's perception of the market median was skewed, because the companies with which it compared its wage scales were not genuinely comparable. The Administrative Law Judge characterized the Company's choice of comparable companies as demonstrating an "aggressive" recruitment policy and recommended the 2.37% overall disallowance advocated by the Department.

The Commission agrees with the Department that the companies with which NSP chose to compare its salaries, especially officers' and executives' salaries, were not truly comparable. NSP is a regional utility. The companies in the comparison group were national and international industrial companies and national utilities. All salaries in the comparison group were weighted equally, despite the fact that utility salaries are generally lower. The Commission therefore agrees with the Department and the ALJ that the comparison study is less than totally credible and has skewed NSP's calculations of the market median.

The Commission also accepts and adopts the ALJ's finding that NSP's base salaries are approximately equal to those paid in comparable markets and that any incentive compensation paid would raise them above market levels. Because the cost of the incentive plan is a useful proxy for the amount by which NSP salaries exceed market rates, and because of serious deficiencies in the incentive plan discussed below, the Commission will disallow the costs of the incentive plan. This does not mean, of

course, that the Company must discontinue the plan. It merely means the Company cannot recover the costs of the plan from ratepayers.

The Commission disagrees with the Department and the Administrative Law Judge that the salary component of NSP's rates should reflect 105% of the adjusted market median. For any regulated utility, recovery of above-average expenses in any category requires explanation and justification. While the "just and reasonable" standard does not automatically translate into "average," that is a good starting point from which to analyze the reasonableness of claimed expenses. In this case the Commission sees no justification for higher than average salary expense.

The Commission appreciates the Company's claim that setting wage levels is a management prerogative the Commission should respect and uphold if at all possible. Clearly, determining wage rates is a key managerial function which seriously affects employee morale and the size of the labor pool available to the Company. At the same time, labor expense is a key component of utility rates. The Commission has a duty to examine every component of rates for prudence and reasonableness and to resolve any doubt in favor of the consumer. Minn. Stat. § 216B.03 (1992). The Commission concludes that managerial prerogative must yield to Commission oversight on the issue of what portion of labor expense is recoverable from ratepayers. Management may of course choose to pay salaries in excess of recoverable amounts.

The Commission has examined total test year labor costs, finds them higher than the market requires, and will disallow the incentive plan expenses which take them above market levels.

c. Incentive Plan Deficiencies

A major reason the Commission rejected the Company's 1991 incentive compensation plan was a Commission finding that the plan improperly transferred risks of operation from shareholders to ratepayers and Company employees.¹ This defect was more obvious in the 1991 plan, which made all incentive plan payments contingent upon Company earnings meeting a specified earnings per share threshold. The current plan, however, retains an earnings per share component in the officers' and executives' plan and in the long-term plans, which are available only to officers and executives.² The Commission continues to consider earnings per

¹ In the Matter of the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota, Docket No. E-002/GR-91-1, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (November 27, 1991) at 55.

² The Company does not expect to meet the plans' earnings per share threshold in the test year and does not seek recovery of amounts attributable to those portions of the officers' and

share thresholds an improper transfer of risk, since ratepayers bear the risks (the costs of incentive compensation) and shareholders reap the benefits (increased earnings per share).

The Commission also continues to believe earnings per share thresholds can jeopardize a utility's commitment to providing safe, reliable, economical service over the long-term by over-emphasizing short-term performance. In most private business contexts, short-term thinking is merely unfortunate. In the public utility context, it can create a public crisis.

Another defect in the plan is the large percentage (up to 30% and 40%) of executives' and officers' pay which can come from incentive compensation. These percentages are simply too high. Their stated purpose is to align officers' and executives' interests more closely with those of shareholders. While officers and executives clearly have a duty of loyalty to shareholders, they also have a duty to exercise independent judgment on behalf of the Company and to give regulators their full cooperation. Offering key decisionmakers large financial rewards for producing short-term shareholder benefits does not promote regulatory efficiency or the long-term fortunes of the Company. Since the public has an interest in ensuring the long-term viability and stability of the Company, this is a serious defect.

Another of the plan's serious defects is that the Company retains the right not to make incentive payments earned under the plan. Management exercised this prerogative in 1992 and did not disclaim its ability to do so in the future. This is a clear case of transferring risk from shareholders to ratepayers. If expenses are unexpectedly high or revenues unexpectedly low, shareholders can offset these losses with funds provided by ratepayers for the incentive compensation program. This runs contrary to the test year concept on which rates are based, and the Commission strongly disapproves.

The Commission also shares the concerns of the RUD-OAG and the SRA about two performance measures: the one linking incentive pay with low rates, as compared to the rates of other utilities, and the one penalizing departments for underspending their budgets by 2% or more. The first measure, linking low rates with incentive pay, seems arbitrary, since most NSP employees have little control over rate levels and since employee productivity is just one of many factors which cause rate differences between utilities. The second measure, spending within 2% of budget, seems counterproductive, since it would likely discourage managers from identifying and implementing cost-saving measures. It also appears to be a meaningless requirement; managers required to spend their budgets will do so, and that performance measure will always be met. The Commission's concern is not to

executives' plans. It does seek Commission concurrence in the plans' design, however.

quibble over details of plan design. The concern is that, to the extent that the performance measures of the plan are perfunctory and do not genuinely depend upon employee performance, the program is largely indistinguishable from a bonus program. While awarding bonuses is well within the discretion of Company management, rate recovery of such amounts is inappropriate given current salary expense.

Finally, the Company has failed to show the incentive program is necessary for dependable operations or that it would produce tangible benefits for ratepayers. The stated goals of the program -- better customer service, greater safety, higher productivity -- are all appropriate but are clearly core values every employee's performance is already expected to reflect. None of the goals or performance measures in the plan differ from the goals and performance measures that would apply without the plan. The Company's work force has performed well in the past without incentive compensation; the Company cited no drop in productivity or work quality making incentive compensation necessary. There is no evidence that an incentive compensation program is required to attract and retain a work force capable of delivering high quality electric service at reasonable rates. With base salaries already at market levels, and work quality already high, the Commission cannot approve rate recovery of additional compensation in the form of an incentive plan.

The Commission has examined the incentive plan as a whole and concludes its benefits are speculative, its drawbacks are real, and its expense is not justified by any demonstrated need. Since NSP base salaries are already competitive in the relevant labor market, expenses associated with the incentive compensation plan will be disallowed.

The Commission finds that the gas utility's jurisdictional Administrative & General expense should be reduced \$994,416 for incentive compensation and \$56,073 for the pension on the incentive compensation.

B. Financial Accounting Standard 106

1. Introduction

In 1990 the Financial Accounting Standards Board (FASB) issued a new standard for the accounting treatment of most non-pension post-employment benefits (Post-Retirement Benefits Other than Pensions, or PBOPs). The Board's Financial Accounting Standard (FAS) 106 called for companies to account for PBOPs on an accrual basis. Prior to the issuance of the standard, most Minnesota utilities, including NSP, had been recognizing these obligations on a cash (or pay-as-you-go) basis.

On September 22, 1992, the Commission issued its generic ORDER ADOPTING ACCOUNTING STANDARD AND ALLOWING DEFERRED ACCOUNTING in Docket No. U-999/CI-92-96. In that Order the Commission stated:

The Commission adopts SFAS 106 accrual accounting for Minnesota utility recordkeeping and ratemaking purposes, subject to Commission review for prudence and reasonableness of the [PBOP] programs, expenses, and all calculations in future rate cases.

Order at p. 6.

NSP adopted FAS 106 accrual accounting as of January 1, 1993.

In its rate case filing NSP sought recovery of its PBOP expenses, which consisted of three components:

1. The year's service cost, the present value of the future benefits earned by current employees during the year;
2. The interest cost, equal to the discount rate multiplied by the accumulated post-retirement benefit obligations; and
3. The amortization of the transition obligation, which is defined as the present value of the unfunded post-retirement benefit obligation on the day FAS 106 is adopted.

In his report, the ALJ recommended allowing recovery of the three components of PBOP expenses.

2. Comments of the Parties

The parties raised a number of issues regarding FAS 106, including: recovery of the transition obligation; the prudence of the Company's PBOP plan; funding of the FAS 106 obligation; and the proper attribution period for FAS 106 accrual.

a. Recovery of the Transition Obligation

In their briefs, the Department, the RUD-OAG and the SRA advocated a sharing of the transition obligation and FAS 106 interest between ratepayers and shareholders.

On July 19, 1993, the Commission clarified its policy regarding a utility's recovery of a transition obligation arising from a change from pay-as-you-go to accrual accounting for PBOPs. In its ORDER AFTER RECONSIDERATION in the Minnegasco rate case, Docket No. G-008/GR-92-400, the Commission allowed Minnegasco recovery of the amortization of the transition obligation associated with prudent and reasonable FAS 106 obligations. The Commission later confirmed its policy in a similar decision regarding US WEST's recovery of the transition obligation associated with prudent and reasonable FAS 106 costs. ORDER AUTHORIZING RECOVERY OF COSTS OF IMPLEMENTING FINANCIAL ACCOUNTING STANDARD 106, Docket No. P-421/M-93-126 (July 21, 1993).

Recognizing that the Commission's policy would be equally applicable in the NSP rate cases, the Department, the RUD-OAG and the SRA all dropped their requests for a sharing of the transition obligation and FAS 106 interest between ratepayers and shareholders.

b. Prudence of the FAS 106 Costs

In his report, the ALJ stated that the Company had met its burden of proof regarding the prudence of its FAS 106 expenses. The ALJ found that the FAS 106 costs were prudent and reasonable, and recommended that any intervenor's challenge to prudence be dismissed.

The RUD-OAG stated that the prudence of the Company's FAS 106 costs could not be proven. The Department stated that it did not believe that the level or nature of the FAS 106 expenses were unreasonable. The SRA recommended that the Commission find that the Company's FAS 106 costs were at least partially imprudent, because the Company failed to switch to accrual accounting before January 1, 1993, and because the Company's pre-FAS 106 PBOP costs were too high.

c. Funding of the FAS 106 Obligation

The ALJ found that the Company should fund its FAS 106 obligations in an external Voluntary Employee's Beneficiary Association (VEBA) trust, to the extent that such funding is tax-advantaged.

The Department advocated 100% external funding of the Company's FAS 106 obligations, to ensure security of the funds for ratepayers.

NSP argued that it should be allowed to fund its FAS 106 obligations internally. The Company stated that this option is less costly than external funding, provides more flexibility for investments, and can be monitored sufficiently by the Commission to provide security for ratepayers. The Company stated further that it preferred a tax-advantaged VEBA trust, should it be required by the Commission to maintain external funding.

d. The Attribution Period for the PBOP Plan

The attribution period is the time period over which actuaries measure the service of an employee who will receive PBOPs. The attribution period is used in calculating the present value of an active employee's expected PBOP obligation.

Under NSP's proposed plan, the SFAS 106 accrual would be calculated using an attribution period which begins when the employee is first eligible for PBOP benefits and ends when the employee achieves full eligibility for benefits. This is the definition of attribution period required by the FASB for FAS 106 financial reporting.

The ALJ agreed with NSP's proposed attribution period for FAS 106 obligations.

The Department and the SRA recommended that the attribution period end not with the onset of eligibility, but with the date of expected retirement. According to these intervenors, this change would reduce costs to ratepayers, and would create a better matching of costs with service provided to ratepayers.

3. Commission Action

a. Recovery of FAS 106 Costs

The Commission agrees with the ALJ that the Company has met the burden of proving that its FAS 106 expenses were prudent and reasonable costs of providing utility service. Testimony showed that the Company's plan benefits and costs were comparable to other utilities in the Twin Cities and around the country. As the ALJ stated at p. 43 of his report, "evidence demonstrates that NSP's retiree medical benefits, and benefits for current employees are near the median in the various comparison groups."

The evidence also shows that the Company took steps, such as the initiation of managed care, to control PBOP expenses in the face of increasing health care costs. NSP downscaled its employee PBOP benefits, while remaining aware of the vulnerability of its retired employees.

The Commission does not agree with the SRA that the timing of the Company's change to accrual accounting indicates that its FAS 106 costs were imprudent. Prior to the establishment of FAS 106, the prevailing, prudent business practice was to account for PBOP costs under the pay-as-you-go method rather than the accrual method. Since the Commission's September 22, 1992 generic decision to sanction accrual accounting for ratemaking purposes, the Company changed to FAS 106 accounting and conformed to the requirements of the Commission's decision. Nothing in the Company's timing or accounting treatment rendered its otherwise reasonable PBOP expenses imprudent.

There is nothing in the record to support the SRA's contention that the Company's pre-FAS 106 PBOP costs were excessive. Even if such evidence had existed, it is the Company's **present** FAS 106 plan, not its past plan, which is before the Commission for consideration. Quoting the ALJ's comments on the same issue, the Commission stated at p. 10 of its ORDER AFTER RECONSIDERATION in the Minnegasco rate case, "the only plan under scrutiny for prudence is that with an effective date of January 1, 1993. There is no direct challenge of the cost levels in that plan."

Having found that the Company's proposed PBOP costs were prudent and reasonable, the Commission will approve the costs for use in setting rates in this docket. As the Commission explained in the Minnegasco reconsideration Order, the transition obligation is an

integral part of the move to FAS 106 accounting; approval of the transition obligation is linked to approval of the costs. As the Commission stated at p. 10 of the Minnegasco reconsideration Order, "[a] transition obligation naturally and inevitably arose from the one time accounting change from cash basis to accrual basis for PBOPs." The Commission will approve full recovery of the amortized transition obligation component of PBOP costs.

Lastly, the Commission finds that the Company's interest costs associated with FAS 106 accrual accounting are reasonable operating costs. The Commission thus approves recovery of this third component of the Company's FAS 106 costs.

b. Funding of the FAS 106 Obligation

The Commission agrees with the ALJ that the benefits of external funding of the FAS 106 obligation outweigh any incremental costs incurred. The additional administrative costs for external funding have been estimated at \$633,000 for the electric utility and \$63,000 for the gas utility. The Commission also recognizes that external funding will cause some loss of investment flexibility and options. These drawbacks, however, are outweighed by the additional security for ratepayers which external funding will bring about. External funding will help ensure that PBOP funds are in place when they are needed, a time which is often in the distant future.

The Commission agrees with the general consensus that external funding should be required under the VEBA form. It is in the best interests of ratepayers to limit the requirement of the external, VEBA funding to the extent that the tax benefits of such funding outweigh the associated expenses. The Commission will require that the external funding mechanism be in place by the time the Company files its next general rate case. By limiting the funding requirement to the extent of tax advantage, and allowing a startup period, the Commission intends to move the process to greater ratepayer security while allowing the Company to develop the most advantageous funding plan.

c. The Attribution Period

The attribution period is the time period over which actuaries measure the service of an employee who will receive PBOPs. The attribution period is used to determine the present value of an active employee's expected benefit obligation.

The FASB requires an attribution period which begins with employee hiring and ends at the date of full employee eligibility for benefits. The Commission agrees with the ALJ that in this set of circumstances it is best to set an attribution period for ratemaking purposes which is parallel to the attribution period established by the FASB for financial reporting purposes. The Commission is not in any way controlled by the FASB in its ratemaking decisions; however, when good reasons otherwise indicate parallel accounting treatment, such treatment is the

most useful and least burdensome for the utility. In this case, the Commission believes that there are good reasons for adopting the FASB method of calculating the attribution period.

An attribution period which ends at the date of full employee eligibility, rather than the employee's projected retirement date, holds less risk of underfunding. Employees who retire at their earliest eligibility age, often 55, are not covered by Medicare until they reach the age of 65. These employees pose a possibility of significant cost to the system. Thus, an attribution period which accrues PBOP costs until the point of eligibility should fund the PBOP system more accurately and securely than an attribution period which accrues costs until a projected retirement date.

The FASB carefully considered extending the attribution period to the projected date of retirement but decided against that method. The FASB stated that an attribution period set at the employee's retirement eligibility date represents an accurate picture of the employment agreement between employer and employee. The Board also decided that the attribution period it approved represents the best possible match between employee service and the PBOP benefits accrued. While the FASB decisions are not binding upon the Commission, they represent carefully reasoned determinations and are persuasive in this context.

Extension of the attribution period, as advocated by the Department and the SRA, would result in decreased costs of \$536,000 for the electric utility and \$53,649 for the gas utility. For the reasons stated, the Commission finds that the benefits to ratepayers outweigh the minimal rate impact. The Commission will approve the method of calculating the attribution period proposed by the Company and recommended by the ALJ.

C. Unbilled Revenues

1. Historical and Factual Background

As a practical matter, it is impossible for the Company to read every meter on the last day of each year. Instead, the Company reads meters throughout the month, and bills customers on a cyclical basis throughout the month. The usage from each customer's meter reading date to the end of the month remains unbilled until the meter is read and the bill prepared in the following month. The term "unbilled revenues" refers to revenues which the Company has earned between the most recent meter reading date and the end of the month.

NSP included in its filing the test year unbilled revenues (the difference in the unbilled revenues recorded at the beginning of the test year and the end of the test year).

In 1992, NSP recognized for financial reporting purposes the unbilled revenues as of December 31, 1991. The total amount of unbilled revenue recorded for Minnesota, North Dakota and South

Dakota was \$76.1 million.

2. Positions of the Parties and Recommendation of ALJ

The RUD-OAG proposed that the Commission recognize the accumulated unbilled revenue for regulatory purposes as extraordinary income and amortize it over four years. The RUD-OAG argued that this income was derived from the sale of gas and is extraordinary in that it does not recur as normal test year income.

The RUD-OAG based its claim that the extraordinary revenue should be recognized for ratemaking purposes on several factors. First, NSP has recognized its accumulated unbilled revenues as revenue for financial purposes. Second, regulatory recognition of the cumulative effect of unbilled revenues represents a change of regulatory accounting that is more consistent with regulatory expense accounting. Third, since every other stakeholder in this income has received benefits from the income, it is only fair and symmetrical that ratepayers receive this credit as well. Finally, this recognition of the utility income from unbilled revenues is consistent with the accounting requested by NSP for the transitional FASB 106 expenses.

The RUD-OAG recommended amortizing \$1,541,240 (gas) and \$55,570,231 (electric), the unbilled revenue at the end of 1990 over four years. The test year adjustment would be \$386,000 (gas) and \$13,892,500 (electric). The use of this time frame (December 1990) precludes any question of double-counting the test year unbilled revenues.

The RUD-OAG proposed two alternative solutions if the Commission does not accept the amortization proposal. First, the unbilled revenue amount adjusted for taxes (\$33,082,070) could be removed from the equity portion of NSP's capital structure. Or second, the rate base could be reduced by the amount of bookings (the 12-31-91 unbilled revenue) so that ratepayers do not pay a return on the booked amounts.

However, the RUD-OAG did not except to the ALJ's findings on the unbilled revenue issue.

The Department's recommended adjustments apply only to the electric utility. Since unbilled revenues are a "common issue" in this case, the Department's arguments are included here.

The Minnesota electric jurisdiction unbilled revenues recorded by NSP as of January 1, 1992 were \$50,578,023. The Department recommended that for ratemaking one-half of these revenues amortized over five years be recognized in test year revenues as extraordinary revenues. The test year adjustment would be \$5,057,802. The Department argued that while NSP recognized these revenues for financial purposes, they have not been recognized for ratemaking purposes. The Department's adjustment is an attempt to reconcile the recognition of these revenues on

the books and the actual receipt of these revenues with the recognition of these revenues for ratemaking purposes.

The Department argued that NSP received the unbilled revenue because NSP's accounting and ratemaking books in the past did not account for the unbilled revenue. Therefore, NSP's revenue requirements in the past rate cases were greater than they would have been had the unbilled method of accounting been used. The Department made illustrative calculations to demonstrate that the use of the billed method of accounting resulted in an under-reflection of revenues in the ratemaking process in the past. The Department used the amount actually booked as a proxy for the effects of the change in accounting methods. The Department contended that now that the accounting methods have been changed there needs to be an adjustment to reconcile the regulated books with the financial books, and to provide ratepayers with a proxy of the revenues that were ignored in ratemaking in the past, in effect a "catch-up" resulting from the change in accounting methods. Since ratepayers paid the expenses (related to the unbilled revenue) when they were booked, they should get credit for the revenues now that they are booked.

NSP argued that the unbilled revenues recorded by NSP in 1992 for financial purposes have already been included in rates. By adjusting NSP's 1991 test year revenue deficiency for test-year unbilled revenue, the Commission included the year end 1991 unbilled revenue amount in rates for that test year. Including the change in unbilled during the year is in effect adding all the year end unbilled revenue and subtracting all the beginning of year unbilled revenues. If the Commission were to accept the Department's and RUD-OAG's proposed adjustment it would be using the same revenues that were used to reduce NSP's test year deficiency in 1991 a second time in 1993 to reduce the deficiency NSP is experiencing in the current year.

The Company argued that on page 47 of the Commission's November 27, 1991 Order in Docket No. E-002/GR-91-001, the Commission determined that including pre-test year unbilled revenues results in a mismatch, stating:

The Commission also agrees with the ALJ's recommendation regarding the RUD-OAG's proposed inclusion of an amortized portion of accrued unbilled revenues. Unbilled pre-test year revenues should not be included in test year revenues, because to do so would be to match twelve months' costs with more than twelve months' revenues. Amortization of these revenues would not change the fact that they are improperly included in test year revenues. The Commission finds that pre-test year revenues should not be included in test year revenues.

In Peoples Natural Gas, Docket No. G-011/GR-92-132, the Commission stated:

[T]he unbilled revenue issue raised by the RUD-OAG

involves a proposed recognition of revenues which the Commission has consistently found do not belong to ratepayers.

The year end 1990 unbilled electric revenues and the pre-test year 1985 unbilled gas revenues that the RUD-OAG proposes to include in this case are the identical revenues which the RUD-OAG sought to have included in NSP's 1991 electric rate case and NSP's 1986 gas case as pre-test year accumulated unbilled revenues. The Commission rejected the RUD-OAG's proposal in both cases. NSP contended that to the extent that the RUD-OAG believed that the Commission's decision in either of those Orders was incorrect it was entitled to seek a reversal by means of pursuing reconsideration with the Commission and, if necessary, an appeal to the courts. It is inappropriate for the RUD-OAG to attack the earlier decisions at this time.

NSP argued that the fact that NSP recorded unbilled revenues on its financial books does not impact the proper ratemaking treatment. In Docket No. E-002/GR-85-558, Order After Reconsideration, at 3 (October 20, 1986) the Commission stated:

The amount of \$3.7 million does not represent a liability owed to ratepayers. It will not appear on the Company's books unless and until the accounting change to begin recording unbilled revenues is adopted. If the adjustment were to acquire form in the accounts of the Company, its substance could be examined for what it really is - a one-time extraordinary adjustment to revenues. That increment to existing revenues during a test year would first be a non-recurring event that did not reflect ordinary operations. Second, it would not represent revenues from test year sales. Third, it would not be an offset to any rate base or expense item found in the test year. As such, the adjustment is not of a character that logically would be included in test year revenues.

NSP argued that the Department's stated rationale for its proposed adjustment plainly violates the prohibition on retroactive ratemaking. The basis of the adjustment is the allegation that NSP collected excessive rates from ratepayers in prior periods because ratemaking did not use the unbilled method of accounting.

The RUD-OAG's first alternative proposal to adjust NSP's capital structure is not justified. Even with the accounting change included, NSP's actual earnings in 1992 resulted in returns below the level authorized by the Commission. NSP noted that none of the intervenors, the RUD-OAG included, have suggested that NSP's proposed capital structure, including its equity component, is unreasonable.

The RUD-OAG's second alternative proposal to adjust NSP's rate base is also not justified. An adjustment to rate base would be

appropriate if the RUD-OAG would demonstrate that NSP ratepayers supplied cash to the Company in advance of receiving service. This is not the case with unbilled revenues. To the contrary, at the time unbilled revenues were recorded on NSP's books, shareholders had advanced the cash necessary to fund the costs of service provided.

The ALJ concluded that there is no need for "consistency" between the FAS 106 issue and unbilled revenue. He recommended that each issue should be decided on its own merits.

The ALJ accepted the Company's position and recommended that the Department recommendation and the RUD-OAG recommendation and alternatives be rejected. He stated that the arguments in favor of including "accumulated" unbilled revenues in this rate case have all been dealt with by the Commission in the past including the financial reporting.

3. Commission Analysis

The Commission agrees with the ALJ that it is not necessary to reach identical decisions for the FAS 106 issue and unbilled revenue issue. Other than the fact that they both are the result of a change in accounting, they are totally unrelated issues. The Commission will decide each on its own merits.

The Commission also agrees with the ALJ that the RUD-OAG and Department have presented no arguments that the Commission has not already thoroughly considered in numerous past proceedings and dismissed. As referred to above, the Commission has determined:

1. that pre-test unbilled revenues do not belong to ratepayers (Docket No G-011/GR-92-132),
2. that inclusion of pre-test year unbilled revenues in the test year will result in a mismatch, with more than twelve months revenue and only twelve months costs (Docket No. E-002/GR-91-001), and
3. that the recording on financial books of pre-test year unbilled revenues does not result in test year revenues (Docket No E-002/GR-85-558).

The Commission also determined that unbilled revenues do not accumulate in Docket No. E-002/GR-85-558, Order at 35:

For example, the Company, the RUG-AG, and the ALJ have implied that the unbilled revenue at the beginning of the test year includes revenues that have been unbilled from the very inception of the Company. In the Commission's view, that characterization is misleading and inaccurate. Generally what is unbilled at the end of any month is the electricity that has been consumed since the prior meter reading date.

The Department and RUD-OAG argued that because the Company booked the unbilled revenue for financial purposes, extraordinary income was created and as such must be included in the test year. The Commission's Order After Reconsideration at 3 (October 20, 1986) in Docket No. E-002/GR-85-558, concluded that this revenue, while extraordinary, is not of a character that logically would be included in test year revenues. The Commission confirms its prior conclusion. The Commission also notes that simply the fact that it is extraordinary does not in and of itself mean that it should automatically be included in, or excluded from rates. An extraordinary revenue or cost must be evaluated on its own merits and a decision made on that basis.

The Department and RUD-OAG argued that the pre-test year unbilled revenues have never been considered for rates and now that the Company has recorded them for financial purposes, ratepayers must be given credit for them. First, the Commission has considered pre-test year unbilled revenues in prior rate cases and consistently rejected their inclusion in test year revenues. Second, the amount of revenue calculated for test year purposes is the result of multiplying the sales and customer forecast times the tariffed rates. The sales and customer forecasts have been considered in prior rate cases. The Commission determined what sales and customer forecast (and therefore revenues) should be used that would result in just and reasonable rates. Any argument that unbilled revenues were not considered and should be included in this test year to rectify that assumes that a correction should be made to the accepted forecast (and revenues). The Commission does not believe that such a correction would be justifiable or necessary.

Based on the above reasoning, the Commission finds that pre-test year unbilled revenues should not be included in this test year.

D. Regulated/Non-regulated Allocations

MEC proposed that NSP be required to follow the cost allocation principles adopted by the Federal Communications Commission (FCC) which result in fully allocated costs, where each unit bears its full share of all the costs. This is the opposite of incremental costing where each unit bears only the additional costs caused by its operation. As a utility develops businesses that are accounted for below the line or are non-regulated, MEC contends that it is important that all costs be fully allocated to protect ratepayer interests.

MEC argued that the Commission's November 10, 1992 Order in Docket No. G-008/C-91-942 that required Minnegasco to Adopt FCC guidelines, also requires NSP to adopt the FCC guidelines. MEC contends that NSP is not following the FCC cost allocation methodology.

MEC argued that as a result of not following the FCC guidelines:

1. NSP will not allocate significant customer-related costs caused by NSP's non-regulated operations, thereby

subsidizing non-regulated operations.

2. NSP will arbitrarily allocate a portion of its common administrative and general cost pool without any factual basis for the use of that level of allocations.
3. NSP will use its revenue allocation to allocate indirect common costs even though the revenue allocation has no relationship whatsoever to costs and will result in subsidization of non-regulated operation.

MEC argued that if the Commission required NSP to follow FCC cost allocation guidelines the result would be to eliminate ratepayer subsidization on non-regulated operations in the amount of approximately \$2.1 million for Minnesota electric. MEC did not quantify the effect on the gas utility.

The Company argued that MEC's allegations are unfounded and stem from a fundamental misunderstanding of NSP's system. NSP's cost allocation system uses the same approach as that adopted by the FCC and meets the principles contained in the FCC regulations. NSP explained that its cost allocation system is composed of a three-step process. First, costs incurred directly for non-regulated activities are directly charged to special accounts which remove those costs from regulated operations. Second, overhead costs attributable to costs which are directly assigned to non-regulated operations are allocated in the system. Third, the non-regulated operations are allocated a portion of joint and common costs. NSP argued that the relevant issue in this case is whether the cost allocation system used by NSP produces reasonable, adaptable, and consistent results.

The Department framed its investigation of NSP's cost allocations between regulated and non-regulated operation with the Minnegasco cost allocation Order in mind. The investigation focused on three issues:

- Does NSP identify and isolate all unregulated investments?
- Does NSP identify and assign direct expenses clearly attributable to unregulated operations?
- Does NSP develop and implement appropriate methods of allocating joint and common costs?

Though it did except to some of NSP's allocators, the Department concluded that the answer to all three questions was "yes." The Department concluded that NSP implemented appropriate controls to identify and separate the Company's investments in unregulated activities and that a review of a large sample of items indicated that most items were being charged properly.

The Department argued that MEC has improperly equated following FCC principles with following the letter of FCC rules. The Department did determine that NSP's methods are consistent with FCC guidelines. The Commission did not and could not order all Minnesota utilities to follow FCC allocation rules in the Minnegasco case. To do so would have been an improper

rulemaking. The Department stated that it appears as if MEC is chiefly concerned with using the exact terminology contained in the FCC cost allocation rules, while the Department is evaluating whether other methods achieve similar reasonable results.

The Department recommended changes in the allocable percentage factors for eight departments which in its opinion more closely reflect the relationship to non-regulated operations. The Department also recommended using an R (revenue) allocator in place of an I (investment) allocator because some operations do not have an investment but would receive benefits from regulated functions.

The Department concluded that with its recommended adjustments, which NSP agreed to accept, the allocation system will result in just and reasonable rates. The Department's recommended adjustments would reduce gas expenses by \$102,712.

The ALJ agreed with the Company and the Department that NSP allocates costs in accordance with a hierarchy similar to that prescribed by the FCC cost allocation rules. Adjusting gas expenses by \$102,712 as recommended by the Department will result in just and reasonable rates.

The Commission agrees with the Company, Department, and ALJ that the cost allocation methodology used by the Company is acceptable and results in reasonable allocations for the purpose of setting rates in this proceeding. The Commission finds that expenses should be reduced by \$102,712. (See section K for the detail of the adjustments.)

E. Rate Case Expenses

NSP requested \$427,000 of test year rate case expenses. The Company proposed a two year amortization period. NSP later agreed that since no party applied for intervenor compensation, it would be reasonable to remove the \$23,000 included in the \$427,000 for intervenor compensation. The Company argued that the average interval between rate cases based on all cases filed since 1975 is 35 months and stated that it would agree to a three year amortization.

The Department recommended that total rate case expenses in this Docket be reduced by \$23,000 to remove the portion for intervenor compensation since it appeared that no one will qualify in this case. The Department recommended that the amortization period for rate case expenses should be four years. The Department argued that it had been almost seven years since the last case and since 1980 the average was approximately four years between cases.

The ALJ agreed with the Department's position.

The Commission agrees with the parties that rate case costs allowed should be \$404,000. The Commission concludes that recent history is more indicative for predicting the future than using a

long period of history. The Company's use of all filings since regulation in 1975 distorts the average length of time between filings because of the frequent filing in the 1970's. The Commission accepts the Department's calculation and finds that four years is a reasonable amortization period for rate case expenses. The annual expense would be \$101,000 which reduces the Company's filed expense by \$113,000.

To evaluate the accuracy of NSP's estimate of rate case expenses, the Commission will require the Company to report its actual rate case expenditures 60 days after all administrative review of this Order has been exhausted.

F. Marketing

NSP test year operating expenses included \$2,411,109 for its marketing programs. The Company stated that customers that participate in the Company's programs improve their energy awareness. NSP's marketing effort is focused on improvement of its base load utilization through nonheating uses. At the hearing, NSP withdrew its request to recover a total of \$91,160 for the piping allowance, natural gas vehicle and booster water heater programs. The Company argued that it has provided information that demonstrates that NSP's gas cooking program is cost effective using a simple payback and net present value (NPV) method. NSP argued that it should be allowed to recover \$239,592 of market research costs. The Company stated that it is important to differentiate between marketing and market research programs. The Company has developed the market research programs since the last rate case to be more knowledgeable of customer needs and thus more customer responsive.

The Department argued that ratepayers should pay for marketing programs only if they are cost effective. NSP did not provide the information necessary to perform a cost-benefit analysis for each of the following marketing programs: Gas Cooking Incentive (\$23,400), Piping Allowance (\$6,660), Natural Gas Vehicle (\$43,500) Booster Water Heating (\$41,000), and Market Research Expense (\$239,592). The Department recommended that the total of these programs (\$354,152) be disallowed. The Department agreed that information in NSP's rebuttal testimony allowed qualitative analysis of the market research program and that those costs should be allowed recovery in rates. The Department's final recommendation is to disallow the cost of the four load building marketing programs totaling \$114,560.

The ALJ agreed with the Department that the Commission has consistently required marketing programs to be cost-effective before the utility can recover those expenses from ratepayers. NSP did not justify four programs. The ALJ recommended that test year expenses should be reduced by \$114,560.

The Commission concludes that NSP has not met its burden of proof and demonstrated that the four contested programs are cost-effective and benefit ratepayers. The Commission denies recovery of these programs in the amount of \$114,560.

G. Advertising

NSP's original filing included \$220,284 for advertising in the test year. In responding to data requests, the Company realized it included \$859 too much. In rebuttal NSP reduced its expenses by \$859 resulting in advertising costs of \$219,425. Both the Department and the ALJ agreed that \$219,425 was the proper test year expense.

There is no disagreement among the parties on this issue. The Commission will accept \$219,425 as a reasonable amount to use for advertising costs in this case.

H. Conservation Programs and Tracker Account

1. Conservation Plan

In its direct testimony, the Department indicated that the Conservation Plan in NSP's rate case filing did not include all of the information required by the Commission's conservation plan outline, which was sent to all gas utilities in September 1986.

In its rebuttal testimony, the Company included specific responses to the items identified by the Department as missing from the filed plan.

In its surrebuttal testimony, the Department indicated that it found the Conservation Plan, as augmented by the Company's rebuttal filing, to be sufficient and adequate for rate case purposes.

The ALJ did not directly address the Conservation Plan.

The Commission agrees with the Department and accepts the Company's augmented Plan.

2. Test Year Conservation Costs and Tracker Balance

NSP's original filing requested recovery of \$1,580,500 in test year CIP costs. The Company's update reduced that amount to \$1,507,064 as approved by the Commissioner of the Department (a reduction of \$73,436 from the original filing).

The Company requested that the tracker balance be offset against any refund. If the tracker balance (\$57,164) can not be offset against a refund, the Company proposed to add that amount to the test year CIP costs.

The Department agreed that the amount of CIP cost approved by the Commissioner of the Department was \$1,507,064. The conservation cost recovery charge (CCRC) is \$0.022901 per Mcf (\$1,507,064 / 65,806,433 Mcf test year sales).

The Department recommended that if the tracker can not be recovered from an interim rate refund, the tracker balance should be amortized over four years. The Department opposed NSP's

proposal to include the tracker balance in the test year CIP budget since NSP would overrecover the tracker balance if a rate case was not filed in one year.

The ALJ agreed with the Department that if the CIP tracker balance can not be recovered from a refund then it should be amortized over four years.

Since there is no disagreement the Commission accepts \$1,507,064 as the correct test year CIP costs. Projected Mcf sales for the test year are 65,806,433. The Commission finds that the appropriate CCRC is \$0.022901. The Commission agrees with the Department and ALJ and finds that any part of the CIP tracker that is not recovered through an interim refund should be amortized over four years.

I. Cost of Gas

The purchased gas expense in the Company's original filing was \$167,864,000. The gas costs included in the Company's present rate revenue was \$166,839,564. The difference is \$1,024,436.

The Department argued that it is necessary to adjust the purchased gas cost by that amount to correct the Company's filing so the same gas costs are used in the revenue and expense calculations. The Department notes that an equal adjustment should be made in the Company's new base cost of gas filing at the end of this case.

NSP stated that the Company does not object to the adjustment recommended by the Department, but emphasizes that the base cost of gas must equal the cost of gas used to establish rates and requests that the Commission affirm this in its final order. The adjustment was caused by NSP's current methodology of calculating PGAs. NSP is proposing to change this methodology and Department witness Lowell agrees with the proposal.

The Company stated that the correct amount of the adjustment is \$989,613. The difference is \$34,823 of interdepartmental gas cost that was not correctly reflected in NSP's original filing. The Department agreed with the correction of the adjustment as proposed by The Company.

The ALJ found that both parties agreed to the adjustment and recommended reducing purchased gas cost by \$989,613.

The Commission finds that all parties agree that it is necessary and appropriate to reduce purchased gas cost by \$989,613. The Commission will accept the agreement and reduce purchased gas cost by \$989,613.

J. Purchasing and Contracting Practices

The Department became concerned about the Company's purchasing and contracting practices as result of allegations raised in NSP's last CIP proceeding (Docket No. E-002/CIP-91-521) and the

Company's announced intent to evaluate contracting out its information processing and other centralized functions.

The Department witness, Dr. Parsons, investigated and reviewed the purchasing and contracting practices of NSP's gas utility starting with NSP's Purchasing Department Policy and Procedures. Dr. Parsons then selected a random sample of 20 items from a forty page listing of disbursements for contracts which was provided by the Company. The Department argued that the contracts sampled show that NSP preselects most of its suppliers, only relying to a limited extent on competitive purchasing.

As a result of its review the Department concluded that the level of costs incurred by NSP is higher than necessary due to poor contracting and purchasing practices. The Department recommended that 15% of the 1993 budgeted contract costs for O&M expense items or \$261,316 be disallowed.

The Department also recommended that NSP be ordered to file a report on its gas system contracting and purchasing practices with respect to gas O&M expense items within three months of the date of the Commission's final order in this proceeding. In this report NSP should explain the criteria it uses to select contractors when it does not require competitive bids and the procedure it uses to evaluate these bids when it does request competitive bids.

NSP argued that the Department witness, Dr. Parsons, has no expertise in the area of contracting practices. Dr. Parsons testified that he has never reviewed the purchasing practices of other Minnesota gas utilities, so he has no way to compare NSP's practices or costs with those of other utilities. He admitted that his audit was performed solely on paper and he did not discuss any of the 20 (sample) contract cost items with NSP personnel to determine if there were facts beyond those on the written page that might be of importance to the audit findings.

NSP argued that Dr. Parsons' excessive cost estimate of 15% was based on an NSP memo from 1988 that stated that the Company could save 15% on sod and boulevard restoration if the Company switched to black dirt and seed from sod. Customers objected to the black dirt and seed so the company returned to using sod and was unable to realize the projected savings. NSP stated that Dr. Parsons' test year adjustment assumed that, because there was a projection in 1988 of savings for a single contract work project in 1989, that those same savings would exist today, five years later, and that the saving projection in a single memo can be applied uniformly to all NSP test year contracts. This assumption is simply erroneous as dictated by common sense and by NSP witness Mr. Nelson's testimony.

The Company argued that it has applied reasonable business management practices which have provided NSP's gas customers with adequate service at reasonable rates. The Department's proposed disallowance is not justified and neither is its reporting requirement proposal.

The ALJ found no basis to suggest that the Company had any systemic problem in its gas utility contracting services. He indicated the Department's recommendation for a 15% adjustment is not supported by the record and should be denied. The ALJ also found that there is no justification for the Department's recommended report.

The Commission agrees with the ALJ and concludes that the Department audit did not reveal any systemic problems showing the Company was paying too much for contracted services. The Commission finds that no adjustment is appropriate in this case.

The Commission finds that the record provides incomplete information about NSP's bidding and contracting practices. The Commission concludes that as part of its long term review of the Company it is appropriate for NSP to provide additional information explaining how it requests bids and how it awards the contracts. Therefore, the Commission will order the Company to file a report on its purchasing practices and procedures within six months of the date of this order. The Company should work with the Department in setting the criteria for the report.

K. Other Adjustments

Certain post-rebuttal adjustments were proposed by NSP to reflect the impact on the gas utility of certain adjustments agreed to in the common issues proceedings. These are:

1. Regulated/non-regulated allocations: The Company identified an error in its cost allocations. The correction of this error reduced Administrative & General (A & G) expense by \$65,255. The Company also agreed to a change in allocations which was recommended by the Department that reduces A & G expense by \$37,457. (Note: These are the specific adjustments summarized in section D, regulated/non-regulated allocations.)
2. Incentive compensation: The Company reduced the amount of incentive compensation included in its filing. This reduced A & G expense by \$12,986.

The Commission accepts these adjustments noting that they must be made in conjunction with the discussion in the specific sections.

L. Sales Forecast and Billing Determinants

1. Forecast Levels

The Company used a combination of forecasting techniques to develop the sales and customer forecasts for the following customer classes: Residential Without Gas Space Heating; Residential With Gas Space Heating; Small Commercial Without Gas Space Heating; Small Commercial With Gas Space Heating; Small Industrial - Firm; Large General Service - Firm; Small Commercial - Interruptible; Large Commercial - Interruptible;

Transportation; and Interdepartmental Sales. Customer growth was forecasted by personnel in NSP's Operating Regions, using knowledge of specific circumstances in their regions. NSP used Ordinary Least Squares (OLS) multiple regression analysis for the sales forecasts of the Residential, Small Commercial, and Small Industrial - Firm classes. These models consist of equations relating historical sales to historical weather, customers, and time. For the Large General Service, Large Commercial - Interruptible, and Transportation customer classes, personnel in NSP's Operating Regions forecasted gas sales individually rather than by class as a whole. For Interdepartmental sales, the Company used an Autoregressive Integrated Moving Average (ARIMA) model; ARIMA is a sophisticated time series analysis.

In its forecast, NSP built in net annual unbilled sales, using the methodology prescribed in NSP's most recently approved electric rate case, Docket No. E-002/GR-91-1.

Total sales of 65,540,566 thousand cubic feet (Mcf) were projected for the test year. Exclusive of Transportation service, the total was 59,359,449 Mcf.

In its prefiled direct testimony, the Department indicated several concerns with the methodology used by NSP. Among the Department concerns was the Company's use of quarterly data, dummy variables, and weather data.

The Department prepared separate forecasts by class for those classes for which NSP used analytical techniques (i.e., OLS or ARIMA models). The Department indicated that it modified the Company's models and data as it believed appropriate.

The Department also analyzed the Company's forecasts which were produced by survey techniques. The Department concluded that those forecasts are acceptable for use in deciding this rate case. The Department also accepted all of the Company's projected customer numbers.

Finally, the Department indicated that the Company's estimated margins for sales to customers on flexible rate schedules are consistent with the margins which NSP has actually received from such customers over the past four years.

The Department's forecasts yielded total projected sales of 65,806,433 Mcf, about 266,000 Mcf higher than the total produced by NSP. Exclusive of Transportation service, the Department's total was 59,625,317 Mcf.

In its rebuttal testimony, NSP indicated that the two forecasts are close and tend to verify each other. Subsequent to the filing of that testimony, the Company filed a letter (dated April 28, 1993) partially relating to its forecast testimony. The Company stated that, while it did not accept all of the particular forecast methods utilized by the Department, it would accept the absolute sales levels for the classes as contained in the Department's testimony. The Company indicated that it had

only recently found out about an error in the weather normalization methodology used by its electric utility and that it would not be able to correct any corresponding errors in its gas sales forecast in the remaining time before the hearings. As a result, at the hearings both parties supported the billing units (i.e., customer numbers and sales projections by class) sponsored by the Department.

The ALJ indicated that NSP's forecast of customer counts (accepted by the Department) is reasonable. He also stated that the Department's sales forecast is reasonable and supported by the record.

The Commission agrees with the analysis of the ALJ and will accept the agreed-upon sales forecast and billing determinants for use in this rate case.

2. Weather Data

Despite their agreement on the forecast numbers, NSP and the Department continued to disagree on one issue related to forecasting in this rate case.

In its forecasting methodology, NSP conducts its weather normalization using 20 years of historical average temperatures calculated from data gathered by the National Oceanic and Atmospheric Administration (NOAA). In calculating average temperatures for a given calendar date, NSP uses eight temperatures per day.

The Department argued that NSP's procedure for determining normal weather for each calendar day is not "standard" and should be changed. According to the Department, NSP uses 20 years of data rather than the 30 years used by NOAA to determine normal weather, and the Company calculates normal weather using a simple average of the readings, whereas NOAA uses a more complex formula. The Department stated that it uses the 30-year NOAA weather series, as does every other gas utility in Minnesota. The Department indicated that the use of a non-standard data series by NSP makes the Department's review of the Company's forecast more difficult and time-consuming. The Department argued that the Commission should order utilities to use the nationally recognized 30-year NOAA weather series in sales forecasts, except upon a showing of good cause.

NSP indicated its opposition to that recommendation by the Department. The Company stated that both the gas and electric utilities have used the 20-year, 8-readings-per-day methodology for many years without concern from the Commission. Further, the Company has used the methodology in all the states where it has customers. The Department's recommendation raises the possibility that the Company would have to maintain two data sets and use different methods in the various jurisdictions. In addition, argued the Company, the choice of data set has only a minor impact on the final outcome of the forecast. The Company argued that the use of either the 30-year NOAA source data or

NSP's 20-year data is reasonable. NSP requested that the Commission reject the Department's recommendation that the Company be required to use the 30-year NOAA data in future gas rate cases.

The ALJ indicated that it is inappropriate to order NSP to use 30-year NOAA data for forecasts in future NSP gas rate cases. He stated that, if the Department desires to impose such a requirement on all companies, it should urge the Commission to adopt a rule to that effect. Until such a rule is adopted, the ALJ added, companies such as NSP are free to use whatever data they choose, subject to the risk of nonacceptance of their proposed forecast for failure to select a proper data set.

For purposes of this rate case, the Commission accepts the Company's procedure for determining normal weather and will not require the Company to change its current methodology. The Commission finds that there is no compelling reason in the record to change that methodology, which has been accepted by several regulatory jurisdictions. Any differences in forecast results likely would be minor and would not justify requiring NSP to construct and use a different data set.

M. Operating Income Statement Summary

Based on the preceding findings, the Commission concludes that the appropriate Minnesota jurisdictional operating income for the test year under present rates is \$14,415,000 as shown below (000's omitted):

Operating Revenues	
Retail Revenues	\$249,617
Unbilled Revenues	1,994
Gross Earning Revenue	4,107
Other Revenues	<u>3,332</u>
Total Operating Revenues	<u>\$259,050</u>
Operating Expenses	
Purchased Gas Cost	\$166,456
Other Production	2,263
Transmission	898
Distribution	14,590
Customer Accounts	5,918
Customer Service & Information	1,465
Sales Expense	432
Administrative & General	13,689
CIP Expense	1,507
Depreciation Expense	14,039
Taxes	
Real Estate, Pers Prop, Other	13,995
Misc - Tax Benefit Transfer	(79)
Gross Earning Tax	4,107
Federal & State Income Taxes	5,846
Deferred Income Taxes	3
Def ITC Amort to Taxes	<u>(403)</u>
Total Operating Expenses	<u>\$244,726</u>
Operating Income before AFUDC	\$14,324
AFUDC	<u>91</u>
Net Operating Income with AFUDC	<u>\$ 14,415</u>

XIII. RATE OF RETURN

A. Introduction

The overall rate of return represents the percentage the utility is authorized to earn on its Minnesota jurisdictional rate base. The overall rate of return is determined by the capital structure, which is the relative mix of debt and equity financing most of the rate base, and the costs of these sources of capital. The Commission will first address the capital structure, then the costs of debt and preferred stock and the cost of equity. Finally, the Commission will put these factors together to derive the authorized overall rate of return on rate base.

Four parties submitted rate of return testimony in this proceeding. Mr. Paul E. Pender testified for NSP, Dr. Luther C. Thompson for the Department, Mr. Matthew I. Kahal for RUD-OAG, and Mr. Peter Ahn for MEC.

B. Capital Structure

1. Summary of the Parties' Positions

After a number of updates to account for errors and changing financial conditions, NSP proposed a capital structure consisting of 38.80% long-term debt, 4.56% short-term debt, 8.26% preferred stock and 48.39% common equity as shown below:

<u>Capital Employed</u>	<u>Amount</u> <u>(Thousands)</u>	<u>Percent</u>
Long Term Debt	\$1,294,312	38.80
Short Term Debt	<u>151,996</u>	<u>4.56</u>
Total Debt	\$1,446,308	43.36
Preferred Equity	\$ 275,493	8.26
Common Equity	<u>\$1,614,259</u>	<u>48.39</u>
Total Capital	\$3,336,060	100.00

The percentages are based on the forecast capitalization for the test year ending December 31, 1993.

After comparing the Company's proposed equity ratio with that of comparable companies, the Department witness supported NSP's proposed capital structure as being reasonable. Dr. Thompson recommended that the Commission continue to closely monitor NSP's rising equity ratio and put the Company on notice that equity ratios beyond the average ratios of companies of comparable risk may not be allowed for regulatory purposes in future cases. The RUD-OAG witness, Mr. Kahal, noted that NSP's proposed capital structure is typical of a strong AA-rated utility, and did not believe the Company's projections were unreasonable.

2. Recommendation of the ALJ

The ALJ found that NSP's proposed capital structure, which included a common equity ratio of 48.39%, was reasonable. He noted that the Company's equity ratio showed a trend similar to the equity ratios for comparable electric and gas companies.

3. Commission Findings and Conclusions

The Commission is charged with determining the most reasonable capital structure for NSP for ratemaking purposes. In making this determination, the Commission finds that the relative proportions of the various forms of capital employed by the Company must be reviewed to ensure that ratepayers are not being required to pay an unnecessarily high cost of capital. The equity ratio is of particular concern. Because common equity is typically the highest cost capital, use of too much common equity in the capital structure could cause an excessive cost of

capital. Conversely, a low common equity ratio could increase the risk that earnings will not be sufficient to pay fixed-cost obligations, causing other financing costs to rise.

The Commission must, therefore, be satisfied that the Company has established a capital structure that properly balances the needs of ratepayers for economy and the needs of investors for safety. If the Commission finds that the Company has not achieved a reasonable balance, the Commission will adjust the capital structure for ratemaking purposes to put it within a reasonable range.

The Commission finds that based upon the comparable group evidence in the record, the capital structure proposed by NSP is reasonable. Mr. Pender submitted evidence demonstrating that equity ratios for comparable AA-rated utilities averaged 50.48% at year-end 1991. Dr. Thompson found average equity ratios of 50.40% for his gas comparable group and 46.26% for his electric comparable group. NSP's proposed equity ratio compares favorably with the equity ratios of utilities of comparable risk, and appropriately balances the competing interests of investors and consumers.

In adopting NSP's actual capital structure for the test year, the Commission is not specifically endorsing NSP's stated financial goals, nor is it advocating the use of a utility's actual capital structure for ratemaking as appropriate in all cases. The Commission continues to reserve its authority to examine a utility's capital structure and adjust it for ratemaking purposes where deemed necessary. NSP will be required to justify its proposed capital structure in future rate proceedings, and the Commission may adjust that capital structure if it finds that the Company's equity ratio is unreasonable for ratemaking purposes.

C. Costs of Long- and Short-term Debt and Preferred Stock

In its original filing, NSP proposed a test year cost of long-term debt of 8.49%, short-term debt of 5.92%, and preferred stock of 5.75%. In its rebuttal testimony, it updated its cost of long-term debt to 8.49%, its short-term debt to 4.65%, and its preferred stock to 5.57%. Later, in response to an OAG information request, NSP further revised its long-term debt cost to 8.05%.

No party challenged NSP's cost of preferred stock. RUD-OAG witness Matthew Kahal challenged NSP's estimates of long- and short-term debt. In his surrebuttal testimony, Mr. Kahal argued that NSP's cost of long-term debt should be 7.76% and its cost of short-term debt should be 4.0%.

Mr. Kahal based his estimate of long-term debt cost of 7.76% on his position that NSP failed to completely account for debt refundings which would occur in the test year. He noted a potential \$4 million savings from refunding a \$100 million pollution control bond (PCB) issue. NSP responded that its long-term debt cost represented its best estimate of refundings and

issuances which would occur during the test year. The PCB issue in question could not be refunded until December, 1993 at the earliest, and the \$4 million savings quoted by RUD-OAG was an annual figure.

Mr. Kahal argued that the cost of short-term debt should be set at 4.0%, rather than the 4.65% advocated by the Company. In response to RUD-OAG information requests, NSP indicated that its short-term debt cost for January, 1993 was 3.349%. In addition, a survey of major forecasting authorities concluded that commercial paper rates are expected to remain below 4.0 percent during 1993.

The ALJ determined that the appropriate cost of long-term debt for NSP is 8.05%. He reasoned that it would be inappropriate to annualize the effect of only one financial transaction on the capital structure, when many other transactions (for example, the \$100 million equity issuance) are likely to occur during the test year. The ALJ found that based on NSP's January, 1993 cost of short-term debt, 4.0% was the most reasonable number to use for the cost of short-term debt. NSP subsequently agreed to this cost.

The Commission accepts the costs of long-term debt of 8.05%, short-term debt of 4.0%, and preferred stock of 5.57%. The Commission concludes that these costs reasonably reflect the costs expected to prevail for NSP during the test year.

D. Rate of Return on Common Equity (ROE)

1. Legal guidelines for Commission Decision-Making

In reaching a decision on the appropriate cost of common equity, the Commission, as an administrative agency, must act both within the scope of its enabling legislation and the strictures of reviewing judicial bodies. Two United States Supreme Court cases provide these general guidelines for Commission rate of return decisions:

- a. The allowed rate of return should be comparable to that generally being made on investments and other business undertakings which are attended by corresponding risks and uncertainties;
- b. The return should be sufficient to enable the utility to maintain its financial integrity; and
- c. The return should be sufficient to attract new capital on reasonable terms.

See Bluefield Water Works and Improvement Co. v. P.S.C., 262 U.S. 679 (1923), and FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944).

No particular method or approach for determining rate of return was mandated by those cases, but the necessity of a fair and reasonable rate of return was clearly stated:

Rates which are not sufficient to yield a reasonable return on the value of the property used, at the time it is being used to render the service, are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment. Bluefield Water Works, 262 U.S. at 690.

The Minnesota Supreme Court has also provided some legal guidelines for Commission decision-making. In Minnesota Power & Light Company v. Minnesota Public Service Commission, 302 N.W. 2d 5 (1980), the Court said:

...The single term "ratemaking" has been used to describe what is really two separate functions: (1) the establishment of a rate of return, which is a quasi-judicial function; and (2) the allocation of rates among classes of utility customers, which is a quasi-legislative function.

...we now hold that the establishment of a rate of return involves a factual determination which the court will review under the substantial evidence standard.

302 N.W. 2d at 9.

In conducting its evaluation of the Commission's decision, the Court explained:

...A reviewing court cannot intelligently pass judgment on the PSC's determination unless it knows the factual basis underlying the PSC's determination. Judicial deference to the agency's expertise is not a substitute for an analysis which enables the court to understand the PSC's ruling. Henceforth, we deem it necessary that the PSC set forth factual support for its conclusion. The PSC must state the facts it relies on with a reasonable degree of specificity to provide an adequate basis for judicial review. We do not require great detail but too little will not suffice.

302 N.W. 2d at 12.

In order to provide the factual basis for its decision required by the Court, the Commission will review the testimony of each of the parties on rate of return on common equity, and the objections raised thereto by other parties. The Commission will also review the recommendations of the ALJ. Finally, the Commission will draw its conclusions from the parties' testimony and determine the proper rate of return.

2. Summary of the Parties' Positions

a. NSP

NSP witness Paul Pender looked at a discounted cash flow (DCF)

model, a risk premium model, and a capital asset pricing model (CAPM) to derive the appropriate ROE for NSP. The Company's official position is that the Commission should grant NSP an ROE of 12.5%.

The DCF analysis attempts to discern the rate of return required by investors through review of market data. The DCF formula includes two terms: the dividend yield (annual dividends divided by the price of the stock) and the expected growth rate.

Mr. Pender used a standard DCF analysis to estimate the required ROE for NSP. He used the average of the monthly high and low stock prices and dividends paid for the last four quarters ending June 30, 1992, adjusted to account for the increase in dividends for the first year. At the time the case was filed, Mr. Pender calculated the dividend yield to be 6.28%. The growth rate was estimated by averaging ten-year (1981-91) historical growth rates in dividends, book value and earnings per share. Mr. Pender used ten years to account for a wide range of economic and financial conditions. He estimated the growth rate to be 5.32%. The result of his DCF analysis yielded an ROE of 11.60%. In rebuttal testimony, Mr Pender updated his DCF estimate of ROE to 11.38%.

NSP also performed a comparable-group DCF analysis. For its comparable group, NSP selected a group of 20 utilities which were rated AA minus or above by both Standard & Poor's and Moody's and are covered in the Value Line Investment Survey. Mr. Pender calculated a comparable group dividend yield of 6.35% and a growth rate of 4.07%, for an ROE of 10.42%. In his rebuttal testimony, Mr. Pender updated the comparable group DCF estimate of ROE to 10.22%.

The RUD-OAG argued that NSP's DCF analysis is flawed because the growth figure is overstated. According to RUD-OAG, investors do not rely exclusively on ten-year data; they also consider shorter periods such as five-year historic periods and analysts' growth estimates in determining growth expectations.

NSP contended that RUD-OAG's criticism of Mr. Pender's analysis demonstrates the inherent subjectivity involved in calculating growth rates using the DCF model. It did not place reliance on five-year trends because they indicate declining earnings which NSP does not anticipate will continue into the future.

NSP believes that the DCF model is limited in its ability to accurately estimate required ROE for companies, and that the results are dependent on the judgement of the person applying the model. It argued that the Commission should consider all the evidence in determining ROE, including its use of the risk premium model and the CAPM.

Mr. Pender presented his risk premium analysis by calculating the average holding period return premium for stocks of the comparable group (20 AA-rated utilities) over those utilities' first mortgage bonds. Based on twenty years of data, he calculated a risk premium of 5.26%. Added to the average yield

on AA utility bonds of 8.55%, the equity risk premium model yields an estimated ROE of 13.81%.

In general, the intervenors argued that the risk premium determination was unreliable due to its volatility and uncertainty, and that the method has been consistently rejected by the Commission. RUD-OAG and MEC argued that the results of the risk premium are very volatile depending on the time period used to calculate holding period returns. RUD-OAG witness Mr. Kahal applied the risk premium methodology to the S&P 500 over the period used by NSP and achieved results which suggested that the S&P 500 was less risky than the utility group - a result which defies conventional risk/return theory.

NSP argued that the risk premium method involves simple calculations which are easy to understand. It suggested that intervenors object to the use of the risk premium simply because it produces a high result.

NSP witness Mr. Pender also used the CAPM to estimate NSP's ROE. The CAPM estimates a company's cost of equity by "measuring" its response to systematic risk. The CAPM is applied by calculating a risk premium for the market over a risk free rate and multiplying it by the Company's beta to arrive at a company-specific risk premium, which is added to the risk free rate to arrive at the required ROE. The beta is a comparison of the volatility of a company's stock price (its "riskiness" to investors) with the volatility of prices of the stock market as a whole. The beta is estimated by several services, such as Value Line and Compustat.

Mr. Pender determined the market risk premium using a study by Ibbotson and Sinquefeld which covers a time period of 1926 to 1990. The equity market risk premium in the study is 7.2%. Using the Value Line beta for NSP of 0.75 and a risk-free rate of 7.67% (the average of long-term U.S. Treasury Bonds for the four quarters ending June, 1992), Mr. Pender estimated the CAPM ROE for NSP of 13.07%. The CAPM ROE for his comparable group, using an average beta of 0.65, was 12.35%.

Intervenors argued that the CAPM is similar to a risk premium method and a great deal of subjectivity exists in estimating the beta. The Department noted that Mr. Pender failed to consider other estimates of beta. RUD-OAG witness Mr. Kahal argued that NSP did not use an appropriate risk-free rate (long-term T-bonds present substantial interest rate risk). In addition, Mr. Kahal performed his own CAPM analysis using an intermediate T-bond and estimated a CAPM ROE of 11.2%. MEC argued that the historical data was obsolete and did not reflect current market conditions.

NSP replied that all methods of estimating ROE are subjective, including the DCF method. The CAPM is easily calculated and does not produce the volatile results that certain applications of the DCF method suggest. With respect to RUD-OAG's criticism, NSP argued that a 30-year bond more closely approximates the holding period of a stock than an intermediate bond.

Mr. Pender, using the three models above, calculated a range of ROE for NSP from 11.38% (his DCF result) to 13.81% (his risk premium result). For the comparable group, he calculated a range of 10.22% (DCF) to 13.81% (risk premium). He recommended a return of 12.5%. To corroborate his studies, Mr. Pender cited 1991 and 1992 return on equity decisions of other state commissions ranging from 10.90% to 13.50%, and averaging 12.32%. NSP-Wisconsin was allowed a 12.0% ROE in its most recent rate case, which set rates for a 1993 test year. The North Dakota Commission, on reconsideration, increased NSP's allowed ROE for 1993 rates to 11.5% (from 11.0%).

NSP argued that returns allowed in other jurisdictions are relevant because NSP must compete nationally with other utilities for equity capital. NSP's ROE must be considered competitive with others or its ability to finance maintenance and construction would be impaired.

MEC noted that in the Order in Docket No. E-002/GR-91-01, the Commission stated that it would not use returns allowed in other jurisdictions if the company could not demonstrate the comparability of the utilities, the rate jurisdictions and the test periods involved in those decisions. According to MEC, NSP had no familiarity with the cases in which the other returns were permitted. RUD-OAG argued that return decisions should be made wholly on the facts related to NSP, and not to other utilities or ratemaking authorities. In addition, 1991 and 1992 decisions are of little use in 1993. The cost of capital has fallen sharply in the last year. The Department noted that basing the allowed ROE on the average of those awarded to other utilities is circular reasoning which bears no relation to NSP data.

NSP reiterated its arguments that other jurisdictions with favorable ratemaking standards (such as interim rates and forecasted test years) consistently authorize returns higher than those granted in Minnesota.

b. Department of Public Service

Department witness Dr. Luther Thompson recommended an ROE of 10.75% for the electric utility and 11.50% for the gas utility. He relied on a DCF analysis of NSP data and of comparable groups of electric and gas utilities.

Dr. Thompson argued that the electric and gas utilities should receive ROEs which appropriately account for the varying risk of the utilities and appropriately assign cost responsibility among the utilities' customers. If the Commission chose to use a single ROE for both utilities, the Department recommended an ROE of 11.0%.

For an NSP-specific return, Dr. Thompson took the average of the 20 day yield (as of January 22, 1993), the third quarter 1992 yield, the one-year annual yield and the two-year annual yield to derive a dividend yield range of 5.9% to 6.1%. He used 6.0% as a reasonable estimate of dividend yield. In determining growth

rate, Dr. Thompson looked at 5 and 10 year growth rates on book value per share (BPS), dividends per share (DPS), and earnings per share (EPS) as well as log linear rates, and internal growth rates. He concluded that an appropriate range of growth rates would be 4.0% to 6.0%. He concluded that the midpoint of that range, or 5.0%, was the appropriate growth rate. Therefore, he estimated the cost of equity for NSP at 11.0%, within a range of 10.0% to 12.0%.

To develop rates for the electric and gas utilities, Dr. Thompson performed a comparable group DCF analysis on a group of nine electric utilities and a group of nine gas utilities with similar betas and risk indices. He used the same analysis as was used for NSP-specific data.

For the gas group, Dr. Thompson estimated a dividend yield of 5.6% to 6.2% and a 5.5% growth rate (midpoint of a range of 5.0% to 6.1%) to determine an ROE range of 11.15% to 11.75%. He concluded that the approximate midpoint of that range, 11.5%, would be an appropriate ROE for NSP-Gas.

NSP criticized Dr. Thompson for failing to adjust his dividend yield for first year dividend growth and for using analysts' growth forecasts. NSP argued that analysts' five-year forecasts are not long-term growth forecasts which are called for in the DCF model. Further, there is no evidence that investors pay attention to these forecasts. In addition, NSP argued that Dr. Thompson failed to include a flotation adjustment, based on his mistaken belief that NSP would not issue common equity in the test year.

Finally, NSP argued that while it is not opposed to the setting of two different returns for gas and electric operations, it seems to add unnecessary complication to the case. NSP is a combination utility, and has only one set of financial objectives for both utilities. NSP witness Mr. Pender did not believe that the risk differences between the two were significant or quantifiable.

The Department argued that the DCF method is the most basic and fair methodology to estimate ROE. The Minnesota Commission has consistently used DCF in making its determinations of appropriate rates of return for Minnesota utilities.

With respect to a flotation adjustment, the Department argued that no significant issuance (in light of the Company's total capitalization) was planned for the year which warrants an adjustment for flotation costs. The Department pointed out that NSP's witness, Mr. Pender, also decided not to make this adjustment.

c. Office of the Attorney General

RUD-OAG witness Mr. Matthew I. Kahal recommended an ROE of 10.6%. He relied on a DCF analysis of NSP-specific data and of a comparable group.

Mr. Kahal argued that a comparable group analysis may give the Commission more guidance than stand-alone data because it smoothes out potentially atypical results of individual firms. For his comparable group, Mr. Kahal used the group proposed by NSP, with the exception of one company which was not listed in Value Line. He estimated a dividend yield by calculating the average monthly dividend yield for each company over six months. The average dividend yield for the comparable group, adjusted for growth, was 6.1%.

To estimate the appropriate growth rate, Mr. Kahal relied to a substantial degree on the earnings retention method, and also looked at historical growth rates and published analysts' forecasts. Mr. Kahal's application of the earnings retention method yielded an estimated growth rate of 3.75% to 4.25%. After checking these figures against historical rates and analyst forecasts, Mr. Kahal concluded that an appropriate range of growth rates would be 4.0% to 4.5%.

Mr. Kahal also proposed a flotation adjustment of 0.1% to 0.2% to account for the expenses that NSP will incur in issuing stock in the test year. He concluded that an appropriate range of ROE for the comparable group would be 10.2% to 10.8%.

Using the same basic methodology on NSP-specific data, Mr. Kahal calculated a dividend yield of 6.0%, a growth rate range of 4.0% to 5.0%, and (including a flotation cost adjustment) a cost of equity ranging from 10.1% to 11.2%. Based on the results of the proxy group (10.5% midpoint) and the NSP-specific (10.65% midpoint) analysis, Mr. Kahal recommended an ROE of 10.6%. He indicated that this ROE was appropriate for both the electric and the gas utilities.

NSP supported the RUD-OAG's addition of a flotation cost adjustment and cited past Commission precedent that flotation costs are included when the utility is issuing common equity in the test year.

d. Minnesota Energy Consumers

MEC witness Mr. Peter Ahn recommended an ROE of 9.4%. He used a DCF analysis based on NSP-specific data and a comparable group analysis.

Mr. Ahn calculated a dividend yield using the average monthly high and low stock prices for the three month period of November, 1992 to January, 1993, adjusted for one-half the estimated growth rate. Mr. Ahn's estimated dividend yield was 6.2%.

In order to estimate the expected growth rate, Mr. Ahn used three methods: forecasted dividend growth estimates derived from Value Line, an earnings retention analysis using 1991 data, and a projected earnings retention analysis using Value Line projections for 1995 through 1997. He estimated a range of growth rates for NSP at 2.2% to 3.2%.

Mr. Ahn's comparison group consisted of electric utilities listed with Value Line, excluding companies which were not traded on the New York Stock Exchange or American Stock Exchange, and companies which had decreased or omitted a dividend in the past four quarters. He applied the DCF model to this group, and to three subsets of this group: Companies with a Value Line safety rating of "1," companies with an S&P stock rating of "A," and companies with an S&P bond rating of "AA-." Mr. Ahn's DCF analysis indicated an estimated range of ROE of 9.0% to 9.7%.

Mr. Ahn also supported his 9.4% recommendation with a Merrill Lynch study which estimated a common equity cost for electric, natural gas and telephone utilities in the Merrill Lynch Universe at 10.2%. Mr. Ahn reasoned that since NSP's bonds are rated as "AA-," the Company is less risky than the average utility and the 9.4% recommendation is supported.

NSP argued that Mr. Ahn's estimate was ridiculously low. It cited recent cases in which Mr. Ahn had been a witness or a witness assistant. In all cases, the recommendation involving Mr. Ahn was the lowest offered, and at least 100 basis points lower than the next lowest witness. In all cases, the Commission awarded ROEs substantially higher than Mr. Ahn's recommendation. In addition, NSP argued that Mr. Ahn could not explain how the Merrill Lynch estimate was calculated or what it represented.

The Department took exception to MEC's almost exclusive reliance on forecasted growth rates, reiterating its position that investors consider all information, including five- and ten-year historical growth rates, in formulating their expectations about growth.

3. Recommendation of the ALJ

The ALJ first determined that it would be more appropriate to view NSP as a single entity, with a single required ROE, than to determine separate ROEs for the gas and electric utilities. The ALJ noted that the combined method is simpler, but the alternative is not overly burdensome. The ALJ chose the unified approach primarily because investors purchasing NSP common stock are forced to look at the combined entity.

The ALJ found that the DCF method continues to be the most appropriate method for determining NSP's required ROE. He further determined that Dr. Thompson's analyses, which are similar to those adopted by the Commission in Docket No. E-002/GR-91-01, continue to produce fair and reasonable results. The ALJ recommended that the Commission adopt a dividend yield of 6.0% and a growth rate of 5.0%. He further found that the resulting ROE of 11.0% should be adjusted to include a flotation cost of 0.15%. Because the Company is issuing common stock in the test year, the inclusion of a flotation adjustment is consistent with past Commission practice. The ALJ recommended an ROE of 11.15% for NSP.

With respect to other methods proposed by NSP to determine ROE, the ALJ noted that all of those methods were rejected by the Commission in Docket No. E-002/GR-91-01. The ALJ found no compelling reasons in this case to recommend deviation from the Commission's past decisions rejecting these methods in favor of the DCF.

4. Commission Findings and Conclusions

The Commission finds that it is most appropriate to consider a single return on equity for both the gas and the electric utilities. NSP is traded as a combination utility and there is no evidence in the record that NSP investors require different returns for the electric and gas portions of the Company. Additionally, the Commission has generally considered company-specific data, when available, the best indicator of required return on equity. Adopting the Department's analysis would require heavy reliance on comparable groups when company-specific data is available.

The Commission finds that the appropriate return on equity for NSP in the test year is 11.0%. In making that determination, the Commission adopts the combined utility testimony of Department witness Dr. Luther Thompson.

The Commission agrees with the ALJ that the DCF method is appropriate for determining the cost of equity for NSP. The DCF method is firmly grounded in modern financial theory, and has been relied on by the Department, RUD-OAG, and MEC in this proceeding and by this Commission in nearly every case decided since 1978. The Commission finds it is reasonable to place primary weight on a direct DCF analysis of data for NSP since NSP is actively traded in the market and its price, dividends and past performance are directly observable.

The cost of common equity cannot be directly observed in the marketplace but can be inferred from market data with the application of reasoned judgment. The DCF method seeks to estimate the return required by investors by using the current dividend yield plus the expected growth in dividends.

After careful evaluation of the record in this case, the Commission concludes that Dr. Thompson's analysis provides the most reasonable balance of long- and short-term market data and expert judgment in determining the appropriate ROE for NSP. Dr. Thompson looked at both shorter (20 day and three month) and longer (one and two year) periods in calculating the dividend yield and estimated a yield of 6.0%. The Commission finds that this dividend yield appropriately recognizes and captures expected trends in the dividend yield during the anticipated regulatory period. Dr. Thompson's dividend yield is also corroborated by the DCF analyses of all other witnesses in this case: Mr. Kahal (6.0%), Mr. Pender (6.07%) and Mr. Ahn (6.2%).

While the current dividend yield is fairly easily observed in the market, the determination of the appropriate growth rate is much

more subjective. The Commission must determine the rate at which investors expect NSP dividends to grow in the future. In applying the DCF method, it is reasonable to assume that investors place some weight on past growth trends in determining future expectations. The analysis of historical data must be tempered, however, with the consideration of current and expected economic trends.

Dr. Thompson's range of growth rates appropriately captures most of the data available to investors for determining growth expectations. His use of five- and ten-year historic data strikes an appropriate balance between recent trends and long-term stability. The use of analysts' forecasts also captures a broad base of expert opinion on future growth rate trends.

Dr. Thompson selected the midpoint of his growth range, 5.0%, as a fair and reasonable estimate of expected growth for NSP. RUD-OAG witness Mr. Kahal included a 5.0% growth rate at the upper end of his growth range, and Mr. Pender calculated a DCF growth rate of 5.32%. The Commission will adopt a 5.0% growth rate as a reasonable balance of the parties' positions.

Although Mr. Kahal's actual growth recommendation of 4.4% to 4.5% is also included in the reasonable range of growth, the Commission will not adopt Mr. Kahal's recommendation. Unlike Dr. Thompson, Mr. Kahal relied on 1992 data to develop his recommendation. The record in this case demonstrates that the Company's poor performance in 1992 was due to weather conditions which are not expected to reoccur in the near future. Reliance on the 1992 data may have served to lower Mr. Kahal's estimate of growth below that which investors will reasonably require. The Commission finds that a 5.0% growth rate is supported by both Dr. Thompson's and Mr. Kahal's testimony.

Combining the 6.0% dividend yield with the 5.0% expected growth rate, the Commission finds that the cost of equity for NSP is 11.00%. The 11.00% is based on substantial evidence in the record and will allow NSP the opportunity to attract capital on reasonable terms and maintain its financial integrity.

The Commission finds that NSP has not sustained its burden of proof in demonstrating that the appropriate cost of equity for NSP is 12.5%. NSP's request is not reasonably linked to any of the methodologies purported to support it. Mr. Pender performed three different analyses, the DCF with a result of 11.38%, the risk premium model with the result of 13.81%, and the CAPM with a result of 13.07%. He also based his recommendation on returns allowed in other jurisdictions and a forecast of a general economic downturn. The Commission finds that Mr. Pender's analysis lacks the clarity and reliability of Dr. Thompson's analysis.

The Commission rejects NSP's reliance on the risk premium and CAPM models in this case. The Commission has long considered the risk premium model unreliable for use as an estimator of return due to the potential volatility of the results from this method;

this record confirms that volatility. The CAPM suffers from many of the flaws of the risk premium analysis as well as the subjectivity involved in determining the beta statistic. The Commission finds that the CAPM is not reliable as a primary indicator of return on equity.

The Commission also finds that there is insufficient evidence in the record to support the use of returns awarded to other utilities in other jurisdictions as a check on the return allowed NSP. NSP offered no evidence as to the comparability of the affected utilities to NSP, nor did it offer evidence as to the comparability of other rate jurisdictions to Minnesota. Furthermore, 1991 and 1992 rate decisions were made based on data for time periods which are likely different from the time periods employed in this 1993 test year.

The Commission rejects Mr. Ahn's analysis, which produces an unreasonably low result. In developing a growth recommendation of 2.2% to 3.2%, Mr. Ahn failed to take into account NSP's historical growth rates. As noted above, the Commission firmly believes that this information is available to and reviewed by investors in determining their required ROE. In addition, the record is not clear whether Mr. Ahn's growth calculation is derived from NSP-specific data or comparable group data. Finally, Mr. Ahn failed to draw a plausible link between his recommendation and studies which he argued supported that recommendation.

Finally, the Commission rejects the recommendation of the ALJ to add a flotation cost adjustment of 0.15% to the required return on equity. The Commission finds that the Company did not request a flotation adjustment and failed to demonstrate that such an adjustment was necessary. In addition, the record did not contain evidence with respect to actual or projected issuance costs.

E. Overall Rate of Return

Based upon the Commission's findings and conclusions on return on equity, cost of debt and preferred stock, and capital structure herein, the Commission finds the overall rate of return for NSP in the test year to be 9.08%, calculated as follows:

<u>Capital Employed</u>	<u>Percent</u>	<u>Cost</u>	<u>Weighted Cost</u>
Long-term Debt	38.80%	8.05%	3.12%
Short-term Debt	4.56	4.00	0.18
Preferred Stock	8.26	5.57	0.46
Common Equity	<u>48.39%</u>	11.00	<u>5.32</u>
Total	100.00%		9.08%

XIV. GROSS REVENUE DEFICIENCY

The above Commission findings and conclusions result in Minnesota jurisdictional gross revenue deficiency for the test year of \$8,335,000 as shown below (000's omitted):

Rate Base	\$213,405
Rate of Return	<u>9.08%</u>
Required Operating Income	\$ 19,377
Test Year Operating Income	<u>14,415</u>
Operating Income Deficiency	\$ 4,962
Revenue Conversion Factor	<u>1.679825</u>
Gross Revenue Deficiency	<u>\$ 8,335</u>

In the test year income statement, the Commission found that the Minnesota Total Operating Revenues at present rates is \$259,050,000. Adding the gross revenue deficiency of \$8,335,000 to this amount results in total authorized revenue from Minnesota customers of \$267,385,000.

XV. RATE DESIGN

NSP and the Department were the only parties submitting testimony and argument relating to rate design.

A. Class Cost of Service Study

1. Introduction

The purpose of the Class Cost of Service Study (CCOSS) is to make a reasonably accurate determination of the nature and levels of costs incurred by the Company in providing service to each of its customer classes. This information is used, along with non-cost factors, in dividing responsibility for recovering the Company's revenue requirement among the classes, and in determining rate structures within the classes.

The CCOSS is performed by functionalizing all the utility's costs, classifying them into cost categories, and allocating them among the classes. Disputes over the proper way to conduct a CCOSS generally relate to either the classification of costs or the allocation of costs.

Broadly speaking, three cost classifications are recognized for gas distributors:

1. Demand-related (or capacity-related) costs;
2. Energy-related (or commodity-related) costs; and
3. Customer-related costs.

Demand-related costs vary primarily with the maximum rate of flow of gas; energy-related costs vary primarily with the total volume of gas flowing; and customer-related costs vary primarily with the nature and number of customers.

NSP provides firm sales service to three classes: Residential, Commercial and Industrial (C&I), and Large General Service (LGS). Two classes receive interruptible sales service: Small Volume Interruptible (SVI) and Large Volume Interruptible (LVI). NSP also provides Firm Transportation, Large Volume Interruptible Transportation, and Small Volume Interruptible Transportation services.

Service to interruptible sales customers may be curtailed by NSP when immediately available gas supply is insufficient to serve both firm and interruptible loads. Similarly, NSP may curtail service to interruptible customers of both sales and transportation services when delivery capacity is insufficient to serve both firm and interruptible loads.

NSP and the Department differed in their proposals for allocation of costs in two categories: feeder mains and associated regulator stations, and twelve-month pipeline demand costs. The Department also requested further studies from the Company.

2. Feeder Mains and Associated Regulator Stations

With respect to the feeder mains and associated regulator stations, NSP proposed a cost allocation based upon class contributions to the system peak, while the Department proposed one based upon non-coincident peak demands of the classes. The ALJ recommended using the Department allocator because the Commission had done that in the Company's 1986 rate case.

The Commission finds that the evidence in this record is that these facilities are designed and constructed as a grid sized to serve the distribution system's firm load on a peak day. Although the facilities provide sufficient capacity to serve downstream interruptible customers much of the year, they are inadequate to provide service to both firm and interruptible load during the system peak. The Commission concludes that the peak-day allocator used by the Company properly reflects the cost causation for these facilities.

3. Allocation of Twelve-month Pipeline Demand Costs

The parties also disputed the proper way to allocate certain twelve-month pipeline demand costs. NSP allocated these, like the feeder mains, on contribution to system peak. The Department said they should be allocated on the basis of an off-peak season design day. Because NSP does not calculate this number, the Department used an energy allocator as a proxy. The ALJ again adopted the Department recommendation, noting the Commission had approved that allocation in the past.

NSP serves firm customers all year around, and it is logical to think that NSP should purchase sufficient twelve-month daily entitlements to meet the peak needs of its firm customers during the non-heating season. It would then buy additional peaking entitlements to serve the difference between its on-peak and off-peak design days. Under these conditions, the Department proposal would be appropriate.

The record shows, however, that NSP is not free to purchase peaking entitlements independently of its twelve-month entitlements. Northern Natural, NSP's pipeline supplier and gas transporter, requires its LDC customers to meet not less than 70% of their peak entitlement needs with twelve-month entitlements. The record is clear that NSP purchases its twelve-month entitlements to satisfy this rule. Because the constraint on NSP's twelve-month entitlements purchases is its system peak needs, and not its off-peak requirements, the Commission concludes that NSP's proposed allocator is the proper one.

4. Studies Recommended by the Department

The Department recommended that the Commission require NSP to identify peaking plant variable operation and maintenance (O&M) costs and allocate them to both firm and interruptible classes in the Company's next gas rate case. NSP opposed this recommendation. The ALJ recommended that the Commission order NSP to examine this issue in its next rate filing, and either make an allocation of variable O&M costs, or explain specifically why an allocation is unwarranted at that time.

The record indicates that interruptible customers will be served some of the time NSP's peaking plants are in operation in the test year. Even though service to interruptible customers is priced primarily on the value of service, not the cost, information from the cost study the Department requested is useful if only to be assured that the variable cost of service to interruptibles does not exceed the revenue gained. Under conditions similar to the test year, therefore, the study will be a valuable guide in determining rates, and should be conducted.

There is also indication in the record that whether interruptible customers will be served in the future from peaking plant operations will be determined based upon decisions that have not yet been made -- such as, how will Northern Natural provide peaking and non-peaking entitlements when FERC Order 636 is fully implemented, and what new requirements will the FERC place upon pipelines and distributors. Test year conditions in NSP's next rate case may be such that interruptible customers will never be served while peaking plants are in operation, or will receive peaking plant service to such a minimal extent that no resources should be expended in performing the allocation.

The Commission, therefore, adopts the ALJ's recommendation that NSP be required to perform the cost study and allocation in its next rate case, or to explain specifically why the study and allocation are unwarranted at that time.

Finally, the Department recommended that NSP be required to file a minimum distribution study in its next rate case. A minimum distribution study attempts to ascertain the minimum average cost of provision of gas service to a class of customers under the assumption that they will only be connected and not consume any gas. Presumably the costs so identified would be classified as customer-related, and the additional costs incurred in providing volumes of gas would be demand-related.

NSP opposed the study, stating that it would be costly to perform and would divert resources from more pressing needs.

The ALJ agreed with the Department.

The Commission adopts the ALJ's recommendation, and will require NSP to file a minimum distribution study in its next gas rate case. The Commission notes that the Company's last two rate cases have featured disputes over the proper allocation of feeder mains and regulator stations, and that the evidence in the two cases has been sufficiently varied to lead the Commission to make one decision in the earlier case, and reverse it in this one. While the minimum distribution study probably would not directly address the feeder mains question, it would certainly shed light on which types of costs are incurred for customers, and which for capacity. In turn, the Commission and all parties would have a greater understanding of cost causation, with less dispute over cost allocation.

B. Allocation of Revenues to Customer Classes

There was substantial agreement among the parties and the ALJ on revenue allocation. The differences directly reflected differences in cost allocation in the CCOSS. Because the Commission adopted the NSP cost allocation, it will also adopt NSP's revenue allocation. The results are these:

Large Volume Interruptible, Interdepartmental, and transportation class margins will remain unchanged. The Small Volume Interruptible class will receive a \$170,521 revenue increase, and the Large General Service class will receive a \$41,460 increase to maintain its relationship with interruptible classes. The remainder of the increase will be apportioned based upon relative contribution to the cost of service, as measured by NSP's CCOSS.

C. Large Volume Interruptible (LVI) Rates

NSP, the Department, and the ALJ agreed that the commodity rate should remain fixed at \$0.21738 per Ccf. This price is equivalent to a Number 6 fuel oil price of \$0.326 per gallon. Test year estimates of Number 6 prices ranged from \$0.22 to \$0.34 per gallon.

The Commission finds that this commodity rate properly reflects the value of gas service to customers of this class, and will adopt it. Because the Commission has adopted the revenue

apportionment proposed by NSP, the monthly customer charge to members of this class will remain fixed at \$275.

D. Small Volume Interruptible (SVI) Rates

The parties and the ALJ agreed on a monthly customer charge of \$100 and a commodity charge of \$0.27359 per Ccf. The Commission finds that rates at these levels properly balance cost and value of service, as well as reasonable continuity of rate design. The Commission adopts the proposed rates.

E. Large General Service (LGS) Rates

Coming into this rate case, the LGS class was divided into large- and small-volume subclasses. This division reflected the previous rate design of NSP's gas supplier, Northern Natural Gas (Northern). That aspect of Northern's rate design is no longer in effect, and NSP proposed the elimination of the subclasses. The Department and the ALJ agreed, and the Commission will approve this change.

NSP and the Department agreed on a monthly customer charge of \$225 and a commodity charge of \$0.21738, the same as the commodity charge for the LVI class. NSP proposed a demand charge of \$14.8753 per Mcf, while the Department proposed \$17.2568. The differences here reflect the differences in revenue allocation discussed above. The Commission has adopted the NSP revenue allocation proposal, and will, therefore, approve a demand charge of \$14.8753 per Mcf.

F. Residential Rates

The parties agreed that the monthly customer charge for this class should increase from \$4.00 to \$6.00. Monthly customer costs shown in the CCOSS are approximately \$12. The Commission will approve the proposed \$6.00 rate.

The commodity charge for this class and for the Commercial/Industrial (C&I) class will be determined from the residual revenue requirement, after revenue is apportioned to all other classes. The commodity rates for these two classes will reflect equal percentage increases on the existing margins.

G. Commercial/Industrial (C&I) Rates

As discussed above, the commodity charge for this class will be determined as a residual of the revenue requirement after revenue responsibility has been apportioned to other classes and charges. The parties agree that the monthly customer charge should remain at \$14.00, and the Commission approves that charge.

The parties proposed that new customers with requirements of 500 Ccf per day or more should be placed on the LGS service schedule. The parties proposed that existing customers of this size should be grandfathered on the C&I rate schedule until January 1, 1996. If the business at a location changes ownership before

January 1, 1996, the customer will be converted to LGS when ownership changes. Finally, NSP agreed to acquire load data related to these grandfathered customers. The Commission will adopt these proposals. The Department proposed that NSP use the new data to educate the grandfathered customers on how their bills will change when the grandfathering period is over. The Commission finds that this is a reasonable proposal, and will adopt it.

H. Transportation Rates

The parties agreed that transportation rates should recover the same non-gas commodity and demand margins as the comparable sales services. Thus the transportation commodity rates for Small Volume Interruptible, Large Volume Interruptible, and Firm services are \$0.07815, \$0.03060, and \$0.03060 per Ccf, respectively. The demand charge for Firm Transportation is set at \$6.9056, reflecting the non-gas demand margin that is part of the LGS demand rate approved above. The Commission approves these rates.

NSP proposed customer charges for the three transportation classes of \$300 per month. The Department proposed that these be increased to \$425 per month. Consistent with its revenue allocation decisions discussed above, the Commission will approve a \$300 per month customer charge for transportation customers.

NSP proposed that the demand and commodity charges for small and large volume transportation customers be consolidated. The Department and the ALJ agreed, and the Commission will so order.

NSP proposed to revise the flexible rate language in its transportation tariffs such that the ceiling of the flexible rate is as far above the fixed margin commodity rate as the floor is below. This proposal promotes consistency with NSP's sales tariffs. The Department and the ALJ recommended approval of this revision, and the Commission will so order.

NSP proposed to clarify its eligibility requirements for transportation customers by switching from a minimum daily volume of 500 Ccf to a minimum monthly volume of 15,000 Ccf. This proposal increases customer flexibility and reduces NSP's administrative burden for checking eligibility. The Department and the ALJ recommended adoption of this proposal, and the Commission will adopt it.

I. Telemetering

NSP proposed to require telemetering equipment for all transportation customers. The Department and the ALJ agreed with this proposal, and the Commission concurs.

NSP proposed to require transportation customers to pay for the cost of telemetering equipment (approximately \$1,650) as an up-front charge. The Department and the ALJ recommended that this cost be recovered instead through the customer charge.

The Commission finds that there are relatively few transportation customers, and that the costs of this equipment can most appropriately be recovered from those who cause them through the up-front charge advocated by the Company. The Commission also finds that the customer charge in effect has not been designed to recover these costs. The Commission concludes that the costs of telemetering equipment should be recovered from transportation customers in an up-front charge.

NSP proposed that if it installs telemetering equipment on a sales customer's premises, it would book the investment and make it part of a subsequent rate case cost recovery request. The Department and the ALJ made no specific recommendations on this proposal. The Commission finds it reasonable, and will adopt it.

J. Seasonal Rates

The Department proposed that rates for firm sales classes should reflect seasonal cost differences to promote efficient use. The Department said that although ideally all capacity costs incurred to meet the peak load during the period November through March should be recovered in this period, a first, phase-in step should be taken in this proceeding by including only demand-related gas costs associated with peak-load months. The Department said the proposal should be implemented through NSP's filing of two base costs of gas: one for the five winter months and one for the off-peak months. NSP opposed this proposal, but the ALJ recommended its adoption.

The Commission notes that there is already seasonal variation in the price of gas to NSP's customers due to the higher commodity cost of gas in the winter period, which is flowed through to customers in the PGA. The decision to change the PGA calculation to a one-month window instead of a three-month average, discussed below, will operate to make monthly variations in gas costs more apparent to consumers.

The Commission also notes that firm Residential and C&I customers not on the Budget Plan currently experience higher bills during the winter season due to the increased volumes of gas consumed during that period.

While the Commission is very interested in reflecting efficient pricing in gas rates, there are a number of issues that it feels require more exploration before it increases the seasonal variations of rates and bills. Specifically, the Commission would like to see:

1. Cost studies showing the total variation of costs by season. Before taking even a limited step, the Commission wants to see what the ultimate goal might be.

2. If a phase-in is deemed appropriate, a proposal for how far and how fast the phase-in should proceed, with discussion of the benefits and potential adverse effects associated with both the timing and the degree of seasonality implemented.
3. A complete proposal for a mechanism to introduce the seasonality. Test year volumes and costs involved in designing the seasonal rates should be identified and measured.
4. A review of any barriers to implementation of the proposal, and a plan for overcoming them. This would include identification of any statutes or rules which would need to be changed or varied in order to implement the proposal.
5. An exploration of the effect of implementation of the proposal on conservation of energy and utility revenue erosion.
6. To the extent possible, an exploration of whether implementation of the seasonal rate proposal would encourage customers to migrate to the Budget Plan as opposed to modifying their seasonal use of gas.

Because these issues have not been examined in this case, the Commission will decline to implement the seasonal rate proposal. The Commission encourages the Department and the Company to work together in reviewing these matters before or during NSP's next rate case.

K. Interruptible Rate Standby Service Requirement

NSP's interruptible tariffs require interruptible customers to maintain standby facilities and fuel inventory to back up their entire gas load for periods of gas curtailment. NSP proposed that customers with process loads which may be shut down during curtailment periods be allowed to size their standby facilities to meet only the needs for continuous space heating.

The Department proposed that NSP completely remove its requirements for standby facilities and alternate fuel supplies. The ALJ agreed.

The Commission agrees with the Department that there is little or no cost basis for discriminating between process and space heating loads. The tariff language at issue here, however, is not about defining different rates, but providing safeguards to NSP's gas distribution system and firm customers. It is entirely possible under the Department proposal for a customer to sign on for interruptible service with no standby facilities or alternate fuel supplies at all. When faced with a curtailment order, such a customer might decide to violate the order, either because the customer might not be caught, or because the cost of penalties assessed might be less than the cost of shutting down (with no

backup facilities, frozen pipes might result). Increasing the penalties or threatening to move customers to firm service would not be sufficient deterrents to this type of behavior. The integrity of service to firm customers should not be jeopardized in this way. The Commission will adopt NSP's proposal.

NSP further proposed that customers using gas for specified end uses confined to the months of April through October would not be required to maintain standby facilities for this load, although they could still be curtailed if necessary. Again, the Department and ALJ proposed to eliminate the restriction to "specified end uses." For the reasons cited above, the Commission will adopt NSP's proposal.

L. Interruptible Market Service Rate

NSP proposed to establish an Interruptible Market Service rate schedule. This service would be available to customers who otherwise would buy gas on the spot market and transport it using NSP's distribution system. It would be available during periods when NSP had system supply gas of its own in excess of its sales customers' needs. The sales rate for this service would be variable, with a minimum rate equal to the sum of the variable cost of gas to be sold plus the minimum transportation rate. NSP proposed that when the cumulative revenues from this service exceed the revenues NSP would have received using the variable cost of gas and the fixed volume charge for transportation, the Company would credit half of the excess to the PGA true-up. It responded to concerns voiced by the Department by proposing that use of the service be conditioned upon NSP's filing with the Department and the Commission the contracts, showing a benefit, or at least no detriment to other customers.

The Department opposed this proposal, and recommended it be approved only if NSP were required to credit the full margin recovered to firm customers.

The ALJ recommended that the Company's proposal be approved, unless the Commission found it administratively unworkable or otherwise too burdensome.

The Commission finds that this proposal presents opportunities for all concerned to benefit. Greater sales volumes with no increased demand charges can reduce the average cost of purchased gas, which is beneficial to firm sales customers. NSP's transportation customers have an opportunity to purchase gas at a delivered price lower than they could get elsewhere. Should NSP's margin collections exceed those the Company would have realized under standard transportation rates, firm customers will see a credit to the PGA true-up and the Company will keep half of the excess as a reward.

The Commission shares the Department concern that there would possibly be an incentive for the Company to seek out low-cost gas specifically for these customers, but believes that two factors completely mitigate this concern. First, in its annual PGA

filing, the Company must demonstrate that it has employed reasonable purchasing practices. Playing favorites with one customer class at the expense of another would constitute an unreasonable purchasing practice, as well as an unwise long-term business strategy. Second, under the condition the Company volunteered, which the Commission will order, NSP must make a filing showing a benefit, or at least no detriment, to other classes before gas is sold under this rate schedule.

The Commission finds that the Department proposed requirement that all margins collected from these sales be credited to firm customers is unreasonable, because it would prevent the Company from keeping even the ordinary transportation margins it would receive if it didn't make sales under this rate schedule. The condition would discourage the Company from entering into any transactions under this schedule, which would deny all parties the potential benefits.

The Commission concludes that NSP's proposal for an Interruptible Market Service rate schedule should be approved, on the condition that the Company makes a filing, including the contract with the customer, showing a benefit, or at least no detriment, to other customer classes.

M. Standby Service

NSP proposed to offer up to 6,000 Mcf of Standby Service to transportation customers for process load at market rates. NSP and the customer would annually negotiate the number of days of service and the availability or demand charge. The commodity rate would be based upon NSP's propane inventory cost, with a base of \$0.26 per gallon of propane (\$0.425 per Ccf of gas). NSP proposed to credit revenues received from this service to firm customers.

The Department requested that the proposal be approved subject to several conditions: that NSP's Maplewood facility expansion is realized as planned, that eligibility is not restricted to process load customers, that NSP uses the annual gas true-up for crediting revenues only until its next rate case, when rates will be established for the service, and that NSP be required to file in its next rate case information requested by the Department to facilitate setting rates for the service.

The ALJ found that the proposal, as modified by the Department, was reasonable.

The Commission will approve NSP's Standby Service proposal subject to all but one of the Department conditions. As discussed in the Interruptible Rate Standby Service Requirement above, the Commission does not intend to jeopardize the reliability of firm service by permitting interruptible customers to take service without maintaining standby facilities and fuel for essential heating needs. The same concerns apply here, so eligibility will be restricted to process load customers.

The Commission concludes that the Standby Service proposal should be approved subject to these conditions:

1. The Maplewood facilities expansion is realized as planned.
2. NSP uses the annual gas true-up for crediting revenues to firm customers only until its next rate case, when rates will be established for the service.
3. NSP will be required to file information in its next rate case, detailed by the Department, to facilitate setting rates for the service.

The Commission will also direct the Company to provide an explanation in its compliance filing of how its proposed tariff language satisfies the criteria of the flexible rates statute, Minn. Stat. § 216B.163 (1992).

N. Limited Firm Service

This rate schedule provides an opportunity for customers subject to curtailment to reserve a specified number of days (up to 10 days per year) of firm gas service, at the discretion of NSP.

NSP proposed three modifications to this rate schedule:

1. The restriction on availability to large volume customers only should be removed.
2. The rate for this service should be set equal to the comparable Emergency Service Rate.
3. The twelve-month period should be set to commence July 1, so as to cover a single heating season.

The Department and the ALJ recommended approval of these modifications, but recommended that NSP be required to carefully monitor use of this rate schedule to prevent interruptible customers from using the service to achieve firm service at relatively low rates.

The Commission will approve the modifications proposed by NSP, and will require NSP to monitor the use of this rate schedule as requested by the Department and the ALJ.

O. Compressed Natural Gas (CNG) Service

The Department recommended that NSP's CNG Service be eliminated because it is discriminatory to some SVI customers. The Company agreed, but said it anticipates the need in the future to address CNG services. It noted that the Energy Policy Act of 1992 emphasizes use of alternate fuels, including CNG. NSP said that, as appropriate, it will bring CNG issues to the Commission.

The ALJ recommended that the CNG Service be eliminated, but that the Commission remain open to re-examining CNG issues in the future.

The Commission will order the elimination of CNG Service, noting that customers with CNG facilities have the SVI rate available to them. The Commission will consider CNG issues from time to time as they are brought forward.

P. Gas Yard Lighting

NSP proposed to eliminate this service, which was closed to new customers in 1973. The Company proposed to convert the three remaining customers to metered service at no cost to the customers. The Department and ALJ recommended approval of NSP's proposal. The Commission finds the proposal reasonable and concludes it should be adopted.

Q. New Area Surcharge

Although NSP's original filing in this case contained a proposal to establish a New Area Surcharge, the Company withdrew the proposal during the case. No Commission decision on this issue is required.

R. Firm Service Interruption Charge

NSP proposed a \$65 Firm Service Interruption charge for C&I customers who disconnect service for periods of a few months, intending to resume. Typically, these customers would disconnect at the end of a heating season, and reconnect at the beginning of the next.

The Department recommended approval of this proposal if it does not apply to customers who remain off the system for more than eight months, nor to a new owner if a change of ownership occurs during a lapse in service.

The ALJ recommended approval of the proposal with the Department modifications.

The Commission finds that without implementation of the Firm Service Interruption charge, some C&I customers could disconnect gas service during the non-heating season to avoid paying the monthly customer charges. Such disconnection and subsequent reconnection is uneconomic for the utility, and unfair to other customers, who then must shoulder the customer-related costs associated with these customers. The Commission finds that the proposed charge is a fair and reasonable deterrent to such action. The Commission also finds that the proposed 8-month limitation and inapplicability of the charge to a new owner properly restrict application of the charge to those who would simply attempt to escape paying for some of the costs they impose. The Commission concludes the proposed Firm Service Interruption charge should be approved, subject to the modifications proposed by the Department.

S. Consolidated Rate Zones

NSP proposed to consolidate its Rate Zones NN and MM into a single rate zone. NSP said that it has achieved integration of its system between the Northern Natural and Viking pipelines, and that the zone distinction no longer made sense.

The Department said NSP's proposal was reasonable because rates for the two zones are now equal and the system is integrated. The Department said that the proposal will affect the rate code of approximately 7,500 customers, but will have no billing impact.

The ALJ recommended approval of NSP's proposal.

The Commission finds that NSP's proposed rate zone consolidation is reasonable, and concludes that it should be adopted.

T. PGA One-Month Window

NSP proposed to change its calculation period for the PGA from three months to one month.

The Department and the ALJ recommended approval of NSP's proposal.

The Commission finds that NSP's proposal should enable the Company to more accurately match purchase costs and revenues, and should reduce exaggerated PGA true-ups. The Commission concludes it should be approved.

U. PGA Tariff Clause Revisions

NSP proposed four revisions to its PGA tariff clause:

1. The PGA should reflect the new base gas costs resulting from this rate case.
2. The PGA should reflect the elimination of pipeline charges and the resulting changes of consolidating the Small- and Large-Volume LGS classes.
3. The PGA should reflect the combination of firm and interruptible commodity costs.
4. The PGA should reflect the rolling-in of peak shaving costs into commodity costs.

The Department recommended approval of NSP's proposal. The Department also recommended a fifth revision (which NSP supported), so that Section II.B of the tariff would read as follows:

Large General Service demand unit cost is defined as the annual system cost of demand capacity divided by the system design day units currently on file with the Minnesota Public Utilities Commission/Department of Public Service.

The ALJ recommended approval of these modifications.

The Commission finds that the proposed revisions insure that the PGA accurately reflects current purchasing practices and the decisions made in this rate case, as well as clarifying that LGS demand units on file with the Department and the Commission must be up-to-date. The Commission concludes that the proposed revisions should be approved.

V. Other Miscellaneous Service Charges

NSP proposed six miscellaneous changes, which were supported by the Department and the ALJ:

1. An increase in the Service Connection charge from \$8.50 to \$10.00.
2. A change in the name of the Service Connection charge to Service Processing charge.
3. Establishment of a \$15.00 Service Reconnection charge for re-establishing service for customers disconnected for non-payment.
4. Establishment of a Service Relock charge of \$100.00 to recover the expense incurred when a customer tampers with locks placed on meters that have been disconnected for non-payment.
5. An increase in the Return Check charge from \$10.00 to \$15.00.
6. An increase in the Account History charge from \$0.50 to \$1.00.

The Commission finds that the proposed charges are cost-justified and that the terminology changes will reduce customer confusion as they will be consistent with terminology used for NSP-Electric service charges. The Commission concludes the changes should be approved.

W. Decoupling

The Department recommended a Commission-initiated investigation into "decoupling" methodologies to determine whether greater energy savings can be achieved in future rate cases. Decoupling refers to efforts to sever the link between utility sales and profits. Under the current system, the utility has an incentive to increase sales to maximize profits. This incentive may be inconsistent with a least-cost planning strategy, particularly

one that features efforts to conserve energy (and reduce sales). Decoupling removes this incentive. The Department suggested that an investigation could be patterned after the Commission's financial incentives investigation, Docket No. E-999/CI-89-212.

NSP agreed that the concept of decoupling deserves study, and the ALJ recommended approval of the Department recommendation.

The Commission has been investigating decoupling informally for approximately a year, in a number of forums. Among these have been a two-day in-house seminar last December, and discussions in the Chairman's Round Table seminars. At this time, the Commission does not feel it has completed the work it wants to accomplish informally in evaluating this issue and its relative importance and urgency compared to other current regulatory issues.

After the Commission accomplishes this work, it will be in a better position to determine whether to undertake formal investigations of this and other issues, and to determine the timing and structure of such investigations. Therefore, the Commission will decline to initiate this formal investigation at this time.

ORDER

1. Northern States Power Company is entitled to increase gross annual Minnesota jurisdictional revenues by \$8,335,000 in order to produce gross annual jurisdictional Total Operating Revenues of \$267,385,000.
2. Within 30 days of the date of this Order, the Company shall file with the Commission for its review and approval, and serve on all parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirement and the rate design decisions contained herein, along with the proposed effective date.
3. The compliance filing filed pursuant to Ordering Paragraph 2 shall contain:
 - a. A breakdown of Total Operating Revenues by type;
 - b. Schedules showing all billing determinants for the retail sales of gas. These schedules shall include but not be limited to:
 - i. Total revenue by customer class,
 - ii. Total number of customers, the customer charge and total customer charge revenue by customer class, and

- iii. For each customer class, the total number of commodity and demand related billing units, the per unit commodity and demand cost of gas, the non-gas unit margin, and the total commodity and demand related sales revenues.
 - c. Revised tariff sheets incorporating the rate design decisions contained in this Order. The Company shall also explain how its proposed tariff language for Standby Service to transportation customers satisfies the criteria of the flexible tariffs statute, Minn. Stat. § 216B.163 (1992).
 - d. Proposed customer notices explaining the final rates.
4. Within 30 days of the date of this Order, the Company shall file with the Commission and serve on the parties, a revised base cost of gas and supporting schedules incorporating the changes made herein. The Company shall also file its automatic adjustment establishing the proper adjustment to be in effect at the time final rates become effective. The Department shall review these filings as it does other automatic adjustment filings.
 5. Within 30 days of the date of this Order, the Company shall file with the Commission for its review and approval, and serve upon all parties to this proceeding, a proposal to make refunds, including interest calculated at the average prime rate, to affected customers.
 6. Within 60 days after all administrative review of this Order has been exhausted, the Company shall file a report of its actual rate case expenditures in this docket.
 7. Within six months of the date of this Order, the Company shall file a report on its purchasing practices and procedures. The Company shall work with the Department in setting the criteria for the report.
 8. Before it sells gas under the new Interruptible Market Service Rate, the Company shall submit a filing showing a benefit, or at least no detriment, to other uses. The filing shall include the proposed contract.
 9. Parties shall have 15 days to comment on the filings required in Ordering paragraphs 2 through 8.
 10. The Company shall acquire load data related to customers grandfathered on the Commercial/Industrial rate schedule. The Company shall use the new data to educate these customers on how their bills will change when the grandfathering period is over.

11. The Company shall monitor the use of the Limited Firm Service rate schedule to prevent interruptible customers from using the service to achieve firm service at the lower interruptible rates.
12. In its next general rate case filing, the Company shall include its external funding mechanism for its FAS 106 obligation.
13. In its next general rate case filing, the Company shall include a minimum distribution study for measuring customer costs.
14. In its next general rate case filing, the Company shall either:
 - a. Identify peaking plant variable operation and maintenance costs and their proper allocation to firm and interruptible classes; or
 - b. Explain specifically why the identification and allocation are unwarranted at that time.
15. In its next general rate case filing, the Company shall provide information to facilitate setting rates for Standby Service to transportation customers.
16. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Susan Mackenzie
Acting Executive Secretary

(S E A L)